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The Honorable Chairman and Members of
the Hawaii Public Utilities Commission
Kekuanaoa Building, 1st Floor
465 South King Street
Honolulu, Hawaii 96813

Dear Commissioners:

Subject: Docket No. 2008-0274 – Decoupling Proceeding
Responses to Questions in Appendix 2 of the NRRI Scoping Paper

Enclosed for filing are the HECO Companies' responses to the questions in Appendix 2 of the Commission's decoupling scoping paper "*Decoupling*" *Utility Profits from Sales: Design Issues and Options for the Hawaii Public Utilities Commission*, prepared by the National Regulatory Research Institute ("NRRI") and submitted to the parties in this proceeding on January 21, 2009.¹ As the Commission requested the parties to respond to these questions within 30 days (February 20, 2009), these responses are timely filed.

The response to Question 1 contains confidential information and is provided subject to the Protective Order approved and filed on January 6, 2009 in this proceeding.

Very truly yours,

Attachments

cc: Division of Consumer Advocacy
Hawaii Renewable Energy Alliance
Haiku Design and Analysis
Hawaii Holdings, LLC, dba First Wind Hawaii
Department of Business, Economic Development, and Tourism
Hawaii Solar Energy Association
Blue Planet Foundation

¹ The "HECO Companies" are Hawaiian Electric Company, Inc., Hawaii Electric Light Company, Inc. and Maui Electric Company, Ltd.

APPENDIX 2 - QUESTION #1

Why do electric utilities need decoupling at this time? Please address decoupling needs created by the utility's rate design and Hawaii's emphasis on electricity strategies that would reduce utility sales. If possible, quantify the need.

- 1.1. Does the administration of the energy efficiency programs by a third-party administrator affect the need for and potential benefits of decoupling?
- 1.2. Is the need for decoupling the same on each island? Please consider the frequency in curtailments of as-available renewable generation.

HECO Companies Response:

Decoupling is made up of two components: sales decoupling and a revenue adjustment mechanism. The sales decoupling component breaks the link between revenue and sales and removes the disincentive for energy efficiency and customer-sited distributed generation that exists under traditional ratemaking. The immediate need for the sales decoupling component is driven by the trend of decreasing sales caused by energy efficiency, conservation, increasing amounts of customer-sited DG, and the poor economy, all of which threaten the financial well-being of the utilities when these sales decreases occur between rate cases.

The second component of decoupling is the revenue adjustment mechanism ("RAM") which compensates the utilities for increases in operating and maintenance ("O&M") costs and the return on and return of investments in infrastructure between rate cases. The immediate need for the RAM is driven by the increase in these costs related to maintaining and improving service reliability and normal inflation.

Both sales decoupling and the RAM are immediately required because traditional ratemaking does not sufficiently provide rate relief to the utilities which will enable them to remain financially sound and capable of implementing the objectives of the HCEI Agreement. Regulatory lag, which provides test year rate relief late in the test year and limited ability to

recover the return on and return of investments placed in service between rate cases, does not offer the utilities a fair opportunity to achieve their authorized rates of return. This constrains the ability of the utilities to attain the goals of the HCEI Agreement.

Decreasing Sales

The HECO Companies are already experiencing rapidly decreasing sales. In HECO's CA-IR-282 response in its 2009 Rate Case, Docket No. 2008-0083, page 2, HECO's 2008 recorded sales were below 2007 levels by [REDACTED] GWh or [REDACTED]. Commercial sales experienced a decrease of [REDACTED] GWh or [REDACTED], while residential sale decreased by [REDACTED] GWh or [REDACTED].

HELCO's 2008 recorded sales were below 2007 levels by [REDACTED] GWh, or [REDACTED]. Commercial sales experienced a decrease of [REDACTED] GWh, or [REDACTED], while residential sales decreased by [REDACTED] GWh, or [REDACTED].

MECO's 2008 recorded sales were below 2007 levels by [REDACTED] GWh, or [REDACTED]. Commercial sales experienced a decrease of [REDACTED] GWh, or [REDACTED], while residential sales decreased by [REDACTED] GWh, or [REDACTED].

The utilities' current rate design is a traditional one. As discussed later in this response, in an environment of decreasing sales, the traditional rate design will not enable the utilities to fully recover their fixed costs, resulting in lower earnings, and adversely affecting the utilities' financial integrity.

HCEI Agreement Commitments:

The following is a list of some of the commitments made by the HECO Companies in the HCEI Agreement:

- Pursue and integrate as much as an additional 1,000 MW of renewable energy resources on Oahu, including approximately 400 MW of wind power from Lanai or

Molokai to be delivered to Oahu via undersea cable systems¹; 60 MW on the Island of Hawaii; and 50 MW on Maui (Issue #1 of the HCEI Agreement). This is a significant increase above the amounts of renewable energy resources currently on each island, and will require large investments in the islands' utility grids. As described in HECO T-1's Rate Case Update, filed December 23, 2008, in order to integrate these amounts of renewable energy sources, the HECO Companies will need to examine the following in a set of HCEI Implementation Studies:

1. Technical requirements of and configuration for the inter-island undersea cable systems to ensure their high availability in order to facilitate the transfer of all available energy from the wind farm.
 2. Modifications and additions needed for existing Oahu and neighbor island AC transmission grids to reliably interconnect power from the inter-island high-voltage DC cables and transmit the wind farm energy to Oahu's distribution system.
 3. Energy storage or flexible generation (providing ancillary services and other attributes such as load following, frequency response, regulation, quick start, fast ramping) needed to offset the variable nature of the wind energy and to minimize the curtailment of wind or other intermittent energy projects.
 4. Modifications needed on existing generating units (such as cycling conversion, etc.) to offset the variable nature of the wind energy and to minimize the "spilling" of wind.
 5. Changes to operational practices and procedures needed to operate the island grids and integrate their operations with the wind farm. (HECO T-1 Update at 13, Docket No. 2008-0083)
- Establish feed-in tariffs to provide predictability and certainty with respect to future prices to be paid for renewable energy and how much of such energy will be acquired.

¹ "The State, ... shall seek federal grant or loan assistance to pay for the undersea cable systems. If needed, additional funding for the cable system will be provided through a prudent combination of tax-payer and ratepayer funding. Hawaiian Electric will be responsible for funding, constructing, operating and maintaining all land-based connections and infrastructure up to the interconnection point with the State-owned undersea cable systems." (HCEI Agreement at 2-3)

This was recognized by the parties to the HCEI Agreement as a critical component to accelerate the development of renewable energy projects and acquisition of such renewable energy by the HECO Companies (Issue #7 of the HCEI Agreement).

- RPS goals will increase to 25% (from 20%) by 2020 and 40% by 2030 (Issue # 9 of the HCEI Agreement). However, through 2015, no more than one-third of the Companies' total RPS may come from imported biofuels used in utility-owned units. These increases in RPS goals will require additional investments in the Companies' transmission and distribution infrastructure to accommodate the increase in renewable energy resources. These additional investments are necessary to maintain system reliability to mitigate, control, balance, and manage the impact of additional intermittent, as available, resources on their systems.
- Energy savings from energy efficiency, demand response, and renewable displacement shall not count toward RPS goals after 2014 (Issue #9 of the HCEI Agreement). In effect, renewable supply-sided generation must replace those resources to attain the RPS goals and increases the need for additional investments in the Companies' transmission and distribution infrastructure to accommodate the increase in renewable energy resources.
- There will be no system-wide caps on net energy metering (Issue #19 of the HCEI Agreement). Instead all distributed generation ("DG") interconnections should be limited on a per-circuit basis to no more than 15% of peak circuit demand. This will allow an increase in the amount of customer-sited renewable generation above currently capped levels and will likely reduce the amount of electricity sold by the HECO Companies had the current (lower) net energy metering caps remain in place.

- Support the development of an Energy Efficiency Portfolio Standard (“EEPS”) for the State of Hawaii (Issue #12 of the HCEI Agreement). The HECO Companies commit to supporting the achievement of goals established in the EEPS which will lower their sales from what would have been experienced without an EEPS. This would then reduce the Companies’ electric revenues, jeopardizing their ability to recover their costs between rate cases.
- Deployment of an advanced metering infrastructure (Issue #13 of the HCEI Agreement) which is a key component to transitioning the utilities’ grids to “smart grids.”
- Transition the utilities’ grids to “smart grids” using automation, communications, analytics and controls to operate the grid more efficiently, reliably, and safely, and improve the integration and use of intermittent renewables, demand-side and decentralized resources (Issue #26 of the HCEI Agreement).

Thus, in the HCEI Agreement, the HECO Companies are committed to: 1) making financial investments in their transmission, distribution, and electricity dispatch system to accommodate increased amounts of renewable resources, 2) accepting large quantities of customer-sited renewable DG, 3) converting the existing grids to “smart grids,” and 4) increasing energy efficiency. Commitments 1 and 3 described above will require substantial investment and expenses; and commitments 2 and 4 will reduce electric sales and revenues necessary to cover the Companies’ fixed costs in the future.

The impact of these commitments is immediate. Goals for renewable generation, energy efficiency and customer-sited generation have been set for 2010, just one year hence (see the

timelines attached to the HCEI Agreement). These major projects in the HCEI agreement also require substantial investments, including the incurrence of labor and non-labor expenses, as part of the implementation process, sometimes years in advance of when projects are actually placed into service. Below is a summary of major initiatives already filed with the Commission or identified so far:

1. The Advanced Metering Infrastructure application filed on December 1, 2008, in Docket No. 2008-0303 ("AMI Application"), in compliance with the HCEI Agreement stated that the estimate of total project costs is \$110,364,000 (AMI Application at 56 and Exhibit 19 at 2). The capital portion of this total project cost is \$65,025,000 (AMI Application at 59 and Exhibit 19 at 7).
2. In HECO T-1 Rate Case Update, filed December 23, 2008, in Docket No. 2008-0083, reflected HCEI-related expense impacts totaling \$3,885,300 as follows:
 - a. HCEI implementation studies, \$2,220,000²;
 - b. HCEI-related labor and non-labor expense \$1,665,300 (HECO T-1 Rate Case Update at 6, Docket No. 2008-0083). Detail regarding these expenses is available on pages 15 to 22 of the HECO T-1 Rate Case Update.
3. The HECO Companies have committed resources to develop and implement the Feed In tariffs as soon as possible. The Commission opened Docket No. 2008-0273 on October 24, 2008 to investigate the implementation of feed-in tariffs. In Order Approving the HECO Companies' Proposed Procedural Order, As Modified, filed January 20, 2009, the Commission requested that the HECO Companies to submit proposed tariffs to implement the Commission's decision in this docket by June 17, 2009. As discussed in the HECO T-11 Rate Case Update, filed December 9, 2009, \$230,000 is anticipated to be spent for outside services to support the feed-in tariffs implementation.

Furthermore, the lead time for renewable project development is long. In order to have the renewable resources on-line in time to meet the HCEI timelines, these projects' developers must secure financing years in advance. Having a financially sound utility as an off-taker of these renewable energy projects is, therefore, necessary years in advance of the in-service dates for these projects.

² This \$2,220,000 excludes another \$677,000 in R&D expense described in the Oahu Electric System Analysis study (See HECO T-14 Rate Case Update at 3).

The Commission's scoping paper ("Scoping Paper") states, "Decoupling is any mechanism that breaks the link between utility sales and earnings, so that reduction in sales leaves utility earnings unaffected. Breaking the link between sales and earnings eliminates the financial penalty incurred by utilities through cost-effective programs that reduce sales."³ Therefore, in recognition of the decreasing sales impact on revenues being experienced by the HECO Companies and the significant impact that the HCEI initiatives have on the Companies' revenues, including the substantial investment that is required on the Companies' part to implement these initiatives, decoupling is one of the mechanisms that the HECO Companies require in order to maintain their financial integrity⁴.

Current Rate Design:

As stated in the Scoping Paper, "In traditional rate design, the fixed (customer) and variable (volumetric) charges do not track the utility's fixed and variable costs. The utility recovers only part of its fixed costs through the fixed charge; it recovers the remainder of its fixed costs through the volumetric charge. As sales decrease, so does the utility's recovery of its fixed costs and its earnings."⁵

The HECO Companies have the traditional rate design referred to above. The residential schedule (Schedule R), small commercial schedule (Schedule G), and street lighting schedule (Schedule F) have customer charges and energy charges. The commercial rate schedules (Schedule H and Schedule J) and large power rate schedule (Schedule P) have customer charges,

³ Commission's scoping paper ("Scoping Paper"), Docket No. 2008-0274, "Decoupling" *Utility Profits from Sales: Design Issues and Options for the Hawaii Public Utilities Commission*, National Regulatory Research Institute, January 2009, page 2.

⁴ HCEI Agreement, page 32, states, "The transition to Hawaii's clean energy future can be facilitated by modifying utility ratemaking with a decoupling mechanism that fits the unique characteristics of Hawaii's service territory and cost structure, and removes the barriers for the utilities to pursue aggressive demand-response and load management programs, and customer-owned or third-party-owned renewable energy systems, and gives the utilities an opportunity to achieve fair rates of return."

⁵ Scoping Paper, page 1.

energy charges, demand charges, and other charges based on the amount of energy and demand charges. Table 1 below shows the percentage of fixed costs that are recovered through volumetric charges (both demand and energy charges) by Company.

Table 1

**Percentage of Fixed Costs Recovered
Through Volumetric Charges**

HECO	91.2%
HELCO	89.6%
MECO-Maui	92.3%
MECO-Lanai	94.1%
<u>MECO-Molokai</u>	<u>91.8%</u>
TOTAL	91.1%

As shown in Table 1 above, the HECO Companies recover approximately 91% of their fixed costs through volumetric charges. Fixed costs are the sum of customer-related and demand-related costs in the rate case cost of service study that is the basis of current rates (HECO test year 2005, HELCO test year 2000, and MECO test year 1999). The volumetric charges are the total revenues from energy charges, demand charges and other charges based on the amount of energy and demand charges from the final rate designs in those respective rate cases. A decrease in sales between rate cases resulting from high fuel costs, a slowing global, national, and local economy, energy efficiency, conservation, and customer-sited DG, reduces the Companies' earnings and negatively impacts their financial health. As discussed in the Scoping Paper, "The larger the proportion of a utility's fixed costs recovered through volumetric charges, the greater the effect sales have on earnings and thus the greater the need for decoupling."⁶

⁶ Scoping Paper, page 6.

Decoupling Quantification:

The need for decoupling has been quantified in part in HECO's 2009 Rate Case Update, filed in November and December 2008 (Docket No. 2008-0083). In its update to HECO T-1, pages 4 and 5, and to HECO T-23, pages 2 and 3, HECO indicated its preference not to revise its 2009 test year revenue requirement to reflect the reduction to its sales forecast in connection with its proposal to establish a revenue balancing account (sales decoupling) to be effective upon the issuance of the interim decision and order in that rate case. Incorporation of the sales forecast reduction in the 2009 test year would have driven down electric sales revenues, offset to some extent by a decrease in fuel expense, purchased power expense and fuel inventory, and resulted in a net increase of \$11,462,000 in the revenue increase for the 2009 test year. No similar numbers have been derived for HELCO or MECO.

1.1. Item 2 of the HECO Companies' comments on the Commission's Scoping Paper filed, on February 10, 2009 states:

"Decoupling still makes sense for the HECO Companies whether or not some energy efficiency programs are independently administered. The reasons include: 1) the fact that the anticipated impact of energy efficiency programs (regardless of who administers them) would be to depress energy consumption and sales, resulting in the Companies' need for rate relief to support on-going costs and capital investment for the infrastructure necessary to connect and integrate clean and renewable resources to the grid and maintain system stability and reliable service for Hawaii's customers (and thereby achieve the commitments memorialized in the HCEI Agreement), 2) the need for a financially healthy and credit-worthy utility to support renewable energy development since independent power producers depend on the utility's credit to finance their projects, 3) the HECO Companies' ongoing involvement in energy efficiency programs for commercial and industrial customers, 4) their ongoing involvement in rate design for all customers, including the contemplated increases in volumetric rates, and 5) their important role in the facilitation of customer sited DG."

- 1.2. While the percentage of fixed costs recovered through volumetric charges, and the goals for renewable energy, energy efficiency, and customer-sited DG differ among islands, decoupling is needed on all islands. All of the HECO Companies are parties to the HCEI Agreement and have made the same commitments to increase renewable energy, energy efficiency, and customer-sited DG.

At the current time, HELCO and MECO are most subject to curtailments of as-available renewable generation. Thus, from this one perspective it might appear that encouraging energy efficiency would not be in the best interest of the existing renewable energy producers because lower system demand could lead to more frequent curtailments. Nevertheless, the HECO Companies are in the process of addressing this issue with “valley-filling” techniques and the transition to “smart grids” (see the HECO Companies’ response to Appendix 2 - Question #10).

The encouragement of energy efficiency and customer-sited DG under decoupling results in overwhelming benefits to the state including a reduced dependence on oil, increased energy sustainability, and enhanced energy security. Decoupling also provides the fair opportunity for the utilities to earn their authorized rates of return and maintain their financial integrity. Therefore, while curtailments of as-available renewable generation do occur, they do not negate the need by all HECO Companies to implement decoupling.

APPENDIX 2 - QUESTION #2

Please propose a preferred decoupling methodology and in doing so, please answer these questions.

- 2.1. Should the decoupling process decouple the utility's earnings (or revenues) from the effects of changes in weather, economic upturns/downturns, taxes, costs of financing, the utility's credit rating or other external variables? How are the sales impacts of efficiency programs segregated from these factors, and how does the commission monitor these factors going forward?
- 2.2. Does decoupling that ensures a utility's earnings associated with lost sales create a disincentive for utilities to manage these costs effectively or to invest in capital projects rather than purchase energy or other services?
- 2.3. Does it eliminate the utility's bias against reduced sales?
- 2.4. Does it accurately decouple sales and earnings (i.e., reinstate authorized earnings associated with lost sales)? Please provide supporting examples and calculations that address how lost earnings are calculated.
- 2.5. Does it encourage customers to be energy efficient?
- 2.6. Is it easy to understand?
- 2.7. Are Hawaii's electric utilities' existing metering and customer service systems adequate to support decoupling? If no, recommend enhancements.
- 2.8. Is it easy to administer (monitoring, audits, hearings, reconciliation)? Estimate the administrative costs including regulatory costs.
- 2.9. If the proposed method herein is different from the method proposed by the Agreement, why is it superior?

HECO Companies Response:

The HECO Companies' preferred decoupling methodology was filed with the Commission as the HECO Companies' Revenue Decoupling Proposal, on January 30, 2009 (including corrections filed February 3, 2009) ("Proposal"). The HECO Companies' proposal includes two mechanisms: 1) the establishment of a revenue balancing account ("RBA") which breaks the link between sales and electric revenue, and 2) the revenue adjustment mechanism ("RAM").

- 2.1. The HECO Companies' preferred method decouples utility revenues (excluding the recovery of fuel and purchased power, DSM, IRP, pension and OPEB, HCEI implementation studies, and SolarSaver expenses, which are recovered through various surcharges and trackers) from sales (including changes in weather and

economic upturns/downturns, costs of financing, the utility's credit rating, and other external variables). However, the HECO Companies' decoupling process will reflect changes in State or federal tax rates in their revenue adjustment mechanisms ("RAM") for the post-test years as agreed in the HCEI Agreement¹.

Sales impacts of energy efficiency programs are not specifically identified and segregated from other external variables under the Proposal and the proposal does not address how the Commission should monitor these factors going forward. The HECO Companies' decoupling proposal is not designed to specifically recover the lost earnings related to energy efficiency, but rather is designed to restore the utilities' cost of service revenue requirements in order to maintain the Companies' financial health and enable them to undertake the commitments made under the HCEI Agreement. (See the HECO Companies' response to PUC Question 5.)

- 2.2. Decoupling does not create a disincentive for utilities to manage these costs effectively or to invest in capital projects rather than purchased energy or other services. It is anticipated that decoupling will enhance the Companies' ability to manage costs and their capital programs more effectively. The HECO Companies' preferred method will allow the Companies to forecast their expected base revenues (excluding revenues from the ECAC and the Purchased Energy Adjustment Clause for fuel and purchased power expenses, and other expenses recovered through various surcharges or trackers) with high certainty before the calendar year begins. As a result, the Companies' will be able to plan and

¹ HCEI Agreement, page 33.

manage costs more effectively within their financial parameters. Under traditional ratemaking, revenues are a function of electricity kilowatthour sales which fluctuate from month to month, based on a number of different external variables. Thus, historically, the Companies' were required to adjust their plans and implementation activities to keep within their financial parameters in order to maintain the Companies' financial health under changing circumstances. By knowing what the minimum level of the financial resources will be available during the upcoming post test year, the incentive to manage costs and continue to invest in the infrastructure required to meet their service obligations as utilities and further implement the HCEI initiatives increase as those efforts are more likely to lead to achievement of the Companies' objectives.

- 2.3. Yes, the HECO Companies' proposed decoupling methodology eliminates disincentives for energy efficiency and customer-sited DG that currently exist under traditional ratemaking by "delinking" revenues from sales.
- 2.4. The HECO Companies' Proposal decouples revenues from sales, but is not designed to recover lost earnings from energy efficiency. It is conceivable that sales decoupling could result in a negative adjustment to customers' bills (i.e., lower customer bills) if weather and economic conditions result in exceptional sales growth that overwhelms the contribution of energy efficiency. As part of the RAM process, targeted electric revenues authorized in the rate case (excluding the recovery of fuel and purchased power, and other expenses recovered through various surcharges or trackers) are adjusted for inflation and deflation that may

occur during the post test years². However, actual O&M expenses must be managed by the HECO Companies and they may be higher or lower than the estimated targeted level. Consequently, the HECO Companies may realize earnings that are lower or higher than the level approved in the rate case. Please see the Companies' Proposal for further details, examples, and calculations.

- 2.5. Yes. The HECO Companies' sales decoupling proposal removes the Companies' disincentive towards promoting energy efficiency and other programs that reduce kWh sales. By removing that barrier for the HECO Companies, the decoupling proposal may, at least indirectly, promote energy efficiency opportunities and encourage customers to be energy efficient.
- 2.6. Yes. The HECO Companies' sales decoupling process (including the preferred RAM proposal) is easy to understand. The RBA process is very similar to that followed by Southern California Edison ("SCE") with only one annual adjustment. Also, only two customer categories (residential and commercial) comprise the RBA. The HECO Companies' proposal for the estimation of RAM amounts for the post test years is also simple to understand. The O&M expenses are identified in twelve categories of expenses as presented in the Companies' rate cases and are escalated using only nine (9) different indices which are forecasted by Global Insight, a firm that is well-recognized for its forecasts of economic variables. The return component of the RAM is based on the last authorized rates of return on rate base and the rate base growth estimate. The rate base growth estimate is based on trended historical rate base data with an overlay of approved

² The RAM also adjusts the targeted revenues for changes in the Companies' rate bases during the post-test years.

capital costs for significant projects which are well documented by the applications for approval that the Companies must submit to the Commission. Please see the HECO Companies' Proposal.

2.7. Yes. The HECO Companies' sales decoupling proposal does not require any special metering or customer service systems to be implemented. No data inputs in addition to those already available are necessary to implement their proposed sales decoupling methodology.

2.8. The HECO Companies' proposed decoupling methodology is also easy to administer. Once the concept and filing procedures are identified in this docket, implementation is expected to be prescriptive with only limited review necessary. Please see the HECO Companies' Proposal.

2.9. The decoupling process proposed by the HECO Companies encompasses the provisions reflected in the HCEI Agreement, page 33:

- The proposal is based on decoupling processes and procedures used by the California electric utilities (primarily SCE's process and procedures);
- The RAM estimation procedure is based on cost tracking indices and not based on customer count, which is also similar to that used by SCE;
- The Companies' proposal calculates revenue adjustments for differences in amounts that will be determined in the Companies' 2009 rate cases and the current cost of operating the utility deemed reasonable (the HECO Companies' RAM proposal reflects anticipated inflation or deflation), return on and of ongoing capital investment (excluding projects that are anticipated

to be recovered through the Clean Energy Infrastructure Surcharge), and any State or Federal tax rate changes;

- The RBA and RAM adjustments are proposed to occur at the same time annually;
- The proposal is designed so that the tracking mechanisms for Commission-approved pension and other post-retirement benefits are maintained.

(Please see the HECO Companies' Proposal for further detail.)

The Companies' proposed decoupling mechanism is also in compliance with Ordering Paragraph 2 of the Commission's Order Initiating Investigation, issued on October 24, 2008, which stated that "The HECO Companies and the Consumer Advocate shall submit to the commission a joint proposal on decoupling that addresses all of the factors identified in their Agreement within sixty days of the date of this Order." .

APPENDIX 2 – QUESTION #3

What actions, if any, are required to identify with accuracy each utility's fixed and variable costs?

- 3.1. What fixed charges are recovered through the utility's volumetric rates by rate component?
- 3.2. Is the information needed to allocate costs into fixed and variable costs included in a current rate filing? If yes, please provide.
- 3.3. How should the Commission differentiate between fixed and variable costs?
 - 3.3.1. What timeframe should the Commission consider in setting fixed and variable costs?
 - 3.3.2. Are some "fixed costs" simply long-run variable costs that appear fixed in the short term and how should this affect decoupling?
- 3.4. To what extent, if any, should the Energy Cost Adjustment Clause (ECAC) be modified if decoupling is enacted? Are any fixed costs recovered via the ECAC, and if so, should they be removed? To what extent should performance incentives inherent in the clause be modified or removed in order to remove the connection between utility sales and earnings? Should these incentives instead be recovered through the other charges?

HECO Companies Response:

The HECO Companies include a cost of service study in their rate case applications. The cost of service study is based on the test year revenue requirement proposed in the rate case. The cost of service study classifies costs as energy-related, demand-related, and customer-related. The cost of service study does not consider whether the test year costs are considered fixed costs or variable costs. The HECO Companies also include a marginal energy cost study in their rate case applications. This study estimates the incremental cost of producing an additional kWh. The marginal energy cost does not address the test year cost estimates, which are the costs that are the basis for the rates.

- 3.1. Almost all of the utility's electric revenues are recovered through either per kWh or per billed kW volumetric charges, or through revenue adjustments that are related to the revenues from per kWh or per billed kW charges, such as service voltage

adjustments, power factor adjustments, and rider savings. Only the customer charge is not based on the volume of kWh sales or billed kWh. Consequently, almost all of the utility's costs are recovered either directly or indirectly through some form of volumetric charge. As shown in Table 1 in the Companies' response to Appendix 2 - Question #1, 91.1% of the customer-related and demand-related costs are recovered through volumetric rates.

- 3.2. In a rate filing, the HECO Companies do not describe test year costs as fixed or variable. As indicated above, the HECO Companies include a cost of service study in all of their general rate case filings. The cost of service study classifies costs into three general categories: customer-related, energy-related, and demand-related. The energy-related costs are primarily fuel costs and the costs of purchased energy. The energy-related costs can serve as a rate case-based estimate of variable costs that is already calculated and presented in the rate case filing.
- 3.3. The Commission's need to differentiate between fixed and variable costs may depend on the application or circumstances that require the differentiation, and the time period (e.g., long term versus short term) for which these costs are to be considered. The HECO Companies' decoupling proposal filed on January 30, 2009 recognizes this relationship between fuel and purchased power energy and kWh sales by proposing to exclude revenues related to the recovery of fuel and purchased power energy costs from the target revenues for the decoupling adjustment.
 - 3.3.1. Again, the timeframe may depend on the application. In the case of decoupling, it may make sense to employ a short term approach and identify variable costs as those costs that vary immediately with changes in kWh sales.

3.3.2. See responses to 3.3. and 3.3.1. above.

- 3.4. The ECAC should not be modified if decoupling is enacted. The ECAC recovers/refunds increases/decreases in the prices of fuel, distributed generation ("DG") energy, and purchased power energy above/below the prices of fuel. DG energy, and purchase power energy reflected in the Companies' base rates that are established in each of the HECO Companies' most recent rate cases. The clause recovers only variable costs, does not recover any fixed costs, and the Companies make no profit on the expenses passing through the clause.

One of the objectives of sales decoupling is to remove the disincentive to the Companies, due to their recovery of a portion of fixed in their volumetric rates, to support energy efficiency programs and customer-sited DG. Since the ECAC recovers only variable costs, there is no disincentive present in the ECAC that needs to be addressed by decoupling. Therefore, the ECAC does not need to be modified if decoupling is enacted.

Furthermore, another objective of decoupling is to provide the basis for a financially sound utility that will have the capability to invest in infrastructure to accommodate increased renewable resources. The ECAC in its present form and as proposed by the utilities in their pending rate proceedings is a critical component to providing for a financially sound utility. The ECAC allows the Companies to recover their fuel and purchased energy expenses incurred to supply electricity to its customers and, therefore, substantially reduces the Company's risk with regard to fuel oil prices. In addition, the ECAC serves to reimburse HECO for prudently-incurred energy costs in a manner that minimizes the negative financial effects caused by

regulatory lag. Therefore, very few regulatory actions would have a more negative impact on the Company's standing with credit agencies and the financial markets than tampering with the ECAC.

Changes to the ECAC are also entirely unnecessary to encourage renewable energy. In large part, it is because of the ECAC that renewable developers are able to finance their projects using the HECO Companies as the financially sound "off-takers" of their renewable energy. The ECAC also allows the utilities to recover the purchased energy expenses for new renewable energy sources immediately (with Commission approval) without waiting for a rate proceeding. Thus, the HECO Companies maintain that the ECAC is a key element in their ability to accommodate increased amounts of renewable energy.

The Companies' ECAC is a strength in the Companies' business risk profile and contributes to the Company's financial integrity. The ECAC is viewed very favorably by the Companies' investors and credit rating agencies as it significantly reduces the risks associated with the HECO Companies' business. In its credit assessment of the HECO Companies, Standard & Poor has in the past cited "an excellent fuel adjustment clause" as strengthening credit quality, and in part, offsetting "reliance on purchase power obligations." The increased renewable energy sources will have a significant impact on the Companies' purchase power obligations, which are considered in the Companies' credit rating. The reliance on purchased power creates debt-like obligations, which are of concern to investors and credit rating agencies. Credit rating agencies impute the amount of debt equivalent for these purchased power obligations.

There is a fixed efficiency factor ("performance incentive") in the ECAC clause related to the efficient operation of the Companies' central station generation units. If the HECO Companies cannot meet the efficiency factor embedded in the ECAC, they recover only a portion of its fuel expenses. On the other hand, if they are more efficient than the fixed efficiency factor, they retain the difference in fuel expense recovery. Instead, the fixed efficiency factor is a performance incentive that encourages the HECO Companies to efficiently convert fuel into electricity. It is effective as an incentive because it directly affects the recovery of fuel expenses and is applied to the revenue mechanism that recovers those expenses. The HECO Companies maintain that applying a similar incentive through another mechanism or adjustment would reduce its effectiveness.

In summary, the ECAC should not be modified because it is unrelated to the fixed cost recovery objectives of decoupling, is critical to the HECO Companies' good standing with credit agencies, is a key component for encouraging and accommodating increased renewable energy, and contains a fuel conversion efficiency incentive that works effectively as is.

APPENDIX 2 - QUESTION #4

What level of specificity is required on a customer's bill to support a decoupling adjustment (e.g., if allocated by rate component, should there be a line item for each part of the decoupling adjustment on the bill)?

HECO Companies Response:

The HECO Companies' decoupling proposal of January 30, 2009 calls for a separate per kWh decoupling adjustments for residential and non-residential customers. The dollar value of such per kWh adjustments can be presented as a separate line item on the customer bill, can be combined with a particular bill component on the customer bill, or can be reflected within each bill component on the customer bill. The existing billing system cannot practically accommodate a line item for a decoupling adjustment for each bill component on the customer bill, and even if it could, such a bill presentation would be unduly complex and likely confusing to most customers.

The HECO Companies propose to present the decoupling adjustments as a separate line item on the customer bill for its simplicity and transparency.

APPENDIX 2 - QUESTION #5

Do all customers share in the benefits of improved energy efficiency, or only those customers who improve their own energy efficiency?

- 5.1. What does the allocation of benefits indicate about the allocation of decoupling's earnings adjustments?
- 5.2. How should the Commission consider each utility's capacity and energy availability in determining the allocation of the decoupling adjustment?
- 5.3. Please propose and discuss an allocation methodology for the decoupling methodology proposed at question 2, above. Include responses to the following questions.
 - 5.3.1. How much of the anticipated change in sales is driven by utility-sponsored programs? Are the programs available to all classes of customers? How are these costs allocated?
 - 5.3.2. Can the utilities' net metering protocols allow behind-the-meter renewable energy to be tracked as a distinct cause of lost sales?
 - 5.3.3. Does customer growth or attrition mask or exaggerate actual energy efficiency trends?
 - 5.3.4. Aside from utility-sponsored programs, do all classes of customers have the same cost-effective opportunities for energy efficiency improvements?
 - 5.3.5. Can and should the decoupling charge be allocated to promote specific energy efficiency goals such as cutting peak demand or reducing carbon emissions?
 - 5.3.6. Does energy efficiency offer greater benefits to the economy in one sector than in another?
 - 5.3.7. The utilities contend that some rate classes produce higher rates of return than others do. To the extent that these differences exist, how should they be addressed under the proposed decoupling process?

HECO Companies Response:

All customers share in the benefits of improved energy efficiency, even customers who do not improve their own energy efficiency. The benefits of reduced energy and demand on the system result in either or both of: 1) the deferral of new generation capacity, and 2) improved ability of the electrical system to ride through temporary shortages of power and avoid load shedding. Of course, customers who improve their own energy efficiency also obtain the benefit of an electricity bill that is lower than those who do not improve their own energy efficiency.

Nevertheless, decoupling is not designed to recover the lost earnings resulting from energy efficiency. The HCEI Agreement identified, and the HECO Companies' proposal contains, two components of decoupling: sales decoupling and a revenue adjustment mechanism ("RAM"). Only sales decoupling is related to sales reductions resulting from energy efficiency as well as other factors. Sales reductions can occur for a variety of other reasons including weather, customer loss, and economic conditions. It is also conceivable that sales decoupling could result in a negative adjustment to all customers' bills (i.e., lower customer bills) if weather and economic conditions result in exceptional sales growth that overwhelms the contribution of energy efficiency¹.

Thus, while decoupling is important because it removes the disincentive to energy efficiency and customer-sited DG, it is not solely related to energy efficiency. Decoupling, including both sales decoupling and the revenue adjustment mechanism, is primarily designed to maintain the utilities' financial integrity such that they can be financially capable of implementing the numerous commitments within the HCEI Agreement.

5.1. The Companies' decoupling proposal is not designed to recover lost earnings. The allocation of the decoupling revenue adjustments are partially related to the allocation of energy efficiency benefits only to the extent that sales reductions, if any, that are caused by energy efficiency will result in a rate increase adjustment to the customer class that experienced the sales reduction. The HECO Companies' allocation of the revenue balancing account ("RBA") adjustment is to all customers; however, the

¹ Between 1996 and 2006, the HECO Companies did have a lost margin adjustment that was specifically designed to recover the lost earnings related to the utilities' energy efficiency demand-side management programs. The lost margin adjustment was allocated to the residential and commercial customer classes in proportion to the energy and demand reductions in each customer class..

Companies propose that separate RBA adjustments be made to two classes of customers: residential customers, and non-residential customers.

Separate RBA adjustments for residential customers and non-residential customers give assurance that the decoupling adjustment will not subsidize one of the two groups at the expense of the other. Furthermore, the aggregation of all non-residential rate schedules into one customer class (instead of adjusting by individual rate schedules) will eliminate the possibility that a closure of a large customer (say in Schedule P) will result in having the RBA adjustment spread among just a few customers remaining in its rate schedule.

5.2. Because all rate schedules have energy charges, but only schedules J and P rates have demand charges, it makes sense to allocate the RBA adjustment by kilowatthours.

5.3. A description of the HECO Companies' proposed RBA adjustment is described on pages 8 to 10 in the Companies' Decoupling Proposal filed on January 30, 2009.

5.3.1. In 2006 and 2007, HECO's demand-side management ("DSM") programs reduced Oahu's sales by approximately 25 and 57 GWH, respectively.² Those DSM programs were available to all classes of customers and the costs of the DSM programs were allocated to the residential and commercial customer classes in proportion to each customer classes' participation in the DSM programs. Sometime in 2009 and thereafter, a third-party DSM administrator will be taking over the administration of the energy efficiency programs. It is the Companies' understanding that contract negotiations between the selected

² These are preliminary estimates for 2006 and 2007 which will be finalized and filed in HECO's Annual Program Accomplishment and Surcharges Report to be filed under Docket No. 2007-0341 by March 31, 2009. For the purpose of estimating the effect on sales, the annualized impacts of HECO's DSM programs were divided in half to reflect the approximate timing of project completion.

vendor and the Commission are proceeding; therefore, the HECO Companies are not certain what the target energy reduction goals will be, nor how those costs will be allocated. Nevertheless, the HECO Companies anticipate that the programs will continue to be available to all classes of customers.

- 5.3.2. No, the HECO Companies' net metering tariff does not require that the energy production of the customer's generator be metered.
- 5.3.3. If the energy efficiency trend is measured by average usage per customer, then the effect of customer growth or attrition on energy efficiency trends would depend on the level of energy consumption of the customers added or lost. For example, if the customer added consumes more than the average energy usage, this would mask the actual energy efficiency trend for existing customers. On the other hand, if the customer lost also consumed more than the average energy use, this might exaggerate the trend for remaining customers.
- 5.3.4. All classes of customers have cost-effective opportunities for energy efficiency improvements that are the same as the opportunities available to customers who participate in utility-sponsored programs. The Companies' utility sponsored programs provide customer incentives and thus provide additional benefits to those customers who participate in these programs. However, customers who choose not to participate in the utility sponsored programs have the same access to those energy efficiency improvement measures as all other customers.

- 5.3.5. It would be difficult to promote specific energy efficiency goals such as cutting peak demand or reducing carbon emissions through the decoupling adjustment. The linkage between customer actions and the decoupling adjustment would be difficult to establish unless the adjustment were specifically designed to reflect specific customer behavior. In that case, there would be a different decoupling adjustment for each customer. Instead, it would be simpler, more direct, and more effective to achieve those energy efficiency goals through the design of the energy efficiency programs.
- 5.3.6. No studies have been completed by the HECO Companies on this subject. However, conceptually, the benefits of energy efficiency are greater if the energy and demand reductions that result from the programs occur during periods when the marginal cost of providing power is highest. Some sectors of the economy may offer more potential for these kinds of reductions than others.
- 5.3.7. Some rate classes produce higher rates of return than other rate classes. This is the result of the revenue allocations to rate classes in general rate cases that are approved by the Commission. The HECO Companies' proposed decoupling adjustments are not intended to alter the Commission-approved class rates of return. The decoupling process and the decoupling adjustments should not be the tools by which class rates of return are aligned and adjusted. Rather, the revenue allocation process in the general rate case has been and continues to be the appropriate forum for determining appropriate class rates of return.

APPENDIX 2 - QUESTION #6

Should the Commission allow the full recovery of lost earnings though the decoupling adjustment or only some percentage of the calculated lost earnings? How much of the risk associated with a change in sales should remain with the utility?

- 6.1. If there is a deviation from 100% recovery, should the deviation be symmetric? For example if sales decrease, does the utility receive 75% of the calculated lost earnings but when sales increase, customers get 100% of the adjustment?
- 6.2. How does a partial adjustment help meet the goals of the Clean Energy Initiative?

HECO Companies Response:

As indicated in the Companies' response to Question #5, decoupling is not designed to recover lost earnings due to energy efficiency. Instead, decoupling is designed achieve the following objectives: 1) to eliminate the disincentive to the Companies to support energy efficiency programs and customer-sited DG, 2) to maintain a financially sound utility that has the financial capacity to maintain and invest in its infrastructure to accommodate increased renewable sources of energy, and 3) to maintain the utility's financial integrity and serve as a credit worthy off-taker of the planned renewable energy projects.

To achieve these objectives, the HECO Companies' decoupling proposal improves upon traditional ratemaking in consideration of the financial challenges presented by the HCEI Agreement. In particular, sales decoupling delinks revenues from sales with the establishment of the Revenue Balancing Account ("RBA") and the revenue adjustment mechanism ("RAM"), reflects inflation or deflation impacts on O&M expenses, and allows the Company the opportunity to recover a reasonable return on rate base. With the approval of the Companies' decoupling proposal, the HECO Companies will be given an opportunity to remain financially sound..

Any discussion of risk must encompass all risks, including the risks associated with efforts to add more renewable energy to the grid (see the HECO Companies' response to Appendix 2 -

Question #1), not just the risks associated with decoupling. These renewable energy commitments increase risk to shareholders in the following areas: 1) dependence on third party suppliers of renewable purchased energy, which if negotiations are unsuccessful, or the renewable IPP fails to honor its purchased power contract, could impact the utilities' commitments under the HCEI Agreement and impact service reliability, 2) delays in acquiring or the unavailability of non-fossil fuel supplies for renewable energy generators, and 3) the impact of intermittent renewable energy generation on the system grid and on the service reliability of the system.

Nevertheless, with regard to the single risk of changes in sales, the HECO Companies maintain that in order for decoupling to achieve its objectives, the Companies must not be exposed to the risk of changes in sales due to energy efficiency, customer-sited distributed generation, weather, economy, etc. This includes the upside risk that the utilities may not participate in any greater than expected revenues should sales growth resume. A further discussion of the relationship of decoupling and risk is provided in the Companies' response to Appendix 2 - Question #7.

- 6.1. Not applicable as decoupling is not designed to recover lost earnings resulting from energy efficiency. See response above, and the response to Appendix 2 - Question #5.
- 6.2. Not applicable as decoupling is not designed to recover lost earnings resulting from energy efficiency. See response above, and the response to Appendix 2 - Question #5.

APPENDIX 2 - QUESTION #7

How much, if any, of a rate-of-return adjustment is commensurate with the greater certainty in earnings provided by decoupling?

- 7.1. To the extent that decoupling results in less financial risk for the utility, how should the commission quantify that effect and how should this be flowed through to the utility's rate of return?
- 7.2. Please quantify decoupling's effect on the utilities' "beta" (a measurement of risk) and what that means to the utility's return and ability to move to a capital structure with more debt.
- 7.3. Can input from the rating agencies be included during development of the decoupling process?

HECO Companies Response:

If an appropriate decoupling mechanism (i.e., a mechanism that decouples sales from revenues and includes a fair revenue adjustment mechanism, or "RAM", to recover increased costs, as is contemplated by the HCEI Agreement), then the utility's revenues should be more stable than they would be without such a mechanism, and its earnings could be more stable.

Taken in isolation, this would mean a lower level of investment risk than an entity with the same level of earnings, but more earnings variation, would have. However, the decoupling mechanism is being proposed in the context of the total commitments and requirements set forth in the HCEI Agreement – and is not being proposed in isolation. There is no indication that investors will perceive a lower level of investment risk as a result of the commitments and requirements in the HCEI Agreement taken altogether.

Utilities in other jurisdictions have implemented decoupling in a "business as usual" operating environment amid declining sales; but never, to the HECO Companies' knowledge, have taken on the risks associated with the numerous massive and substantive projects similar to those called for in the HCEI Agreement at the same time. S&P has recognized the significance

of the HCEI Agreement for HECO as reflected in Standard & Poor's ("S&P") November 26, 2008 report on HECO (Attachment 1).

In this report, S&P states:

Credit concerns around the CEI [Hawaii Clean Energy Initiative] focus on three areas: the feasibility of the plan and what the ramifications are for HECO if it cannot meet the ambitious program outlined in the CEI, the costs of CEI and whether ratepayers will ultimately be willing to bear them, and the potential impact on reliability. (Attachment 1 at 2.)

...

Electric system reliability will also need to be a major consideration going forward, as the issues presented by integrating substantial intermittent solar, wind, and distributed-generation resources is not trivial. (Attachment 1 at 3.)

...

Also of interest is the state's intention to develop an undersea transmission cable ... to bring to Oahu wind power from to-be-constructed large-scale projects developed on other islands....the initiative contemplates that HECO might be a co-partner in financing, and could possibly issue debt to support the project. The details on any such arrangement would be important to credit quality.... (Attachment 1 at 3.)

Any financial risk assessment must also take into consideration the impact of the massive additional renewable energy resources being taken on by the HECO Companies in additional purchased power agreements ("PPAs") on the HECO Companies' balance sheets. S&P already adds about \$568 million in imputed debt from HECO's current PPAs to assess HECO's credit risk. The additional PPAs resulting from the HCEI Agreement will undoubtedly make this imputed debt calculation much higher. And the HECO Companies must balance the capital structure accordingly.

The specific details of the decoupling mechanism plan are under development and the consequences of implementation for the Companies are not yet known. Any attempt to assess the impact on the HECO Companies' risk profile at this point would be speculative.

Additionally, as discussed above, any risk profile assessment must also take into considerations the risks associated with the many projects to be undertaken under the HCEI Agreement.

The HCEI Agreement

The far-reaching nature of the HCEI Agreement presents new and increased risks to the Companies, such as (1) the dependence on third-party suppliers of renewable purchased energy, which could impact the utilities' achievement of their commitments under the HCEI Agreement and/or the utilities' ability to deliver reliable service; (2) the impact of intermittent power to the electrical grid and reliability of service if appropriate supporting infrastructure is not installed or does not operate effectively; (3) the likelihood that the utilities may need to make substantial investments in related infrastructure, which could result in increased borrowings and, therefore, materially impact the financial condition and liquidity of the utilities; and (4) the commitment to support a variety of initiatives, which, if approved by the Commission, may have a material impact on the results of operations and financial condition of the utilities depending on their design and implementation.

The Hawaiian Electric Companies have been negotiating with developers of proposed projects to integrate more than 1,000 MW from a variety of renewable energy sources, including solar, biomass, wind, ocean thermal energy conversion, wave, and others. This includes HECO's commitment to integrate, with the assistance of the State of Hawaii, up to 400 MW of wind power into the Oahu electrical grid that would be imported via a yet-to-be-built undersea transmission cable system from wind farms proposed by developers to be built on the islands of Lanai and/or Molokai. HECO, along with the other parties, have committed to work together to evaluate, assess and address the operational challenges for integrating such a large increment of wind into its grid system on Oahu. The State and HECO have agreed to work together to ensure

the supporting infrastructure needed for the Oahu grid is in place to reliably accommodate this large increment of wind power, including appropriate additional storage capacity investments and any required utility system connections or interfaces with the cable and the wind farm facilities.

The HCEI Agreement also includes a number of other undertakings intended to accomplish the purposes and goals of the Hawaii Clean Energy Initiatives, subject to Commission approval and including, but not limited to: (a) promoting through specifically proposed steps greater use of solar energy through solar water heating, commercial and residential photovoltaic energy installations and concentrated solar power generation; (b) providing for the retirement or placement on reserve standby status of older and less efficient fossil fuel fired generating units as new, renewable generation is installed; and (c) installing Advanced Metering Infrastructure.

By way of example, Hawaii's existing RPS law requires electric utilities to meet an RPS of 8% of KWH sales by December 31, 2005, 10% by December 31, 2010, 15% by December 31, 2015, and 20% by December 31, 2020. The RPS law provides that at least 50% of the RPS targets must be met by electrical energy generated using renewable energy sources, such as wind or solar, versus from the electrical energy savings from renewable energy displacement technologies (such as solar water heating) or from energy efficiency and conservation programs. The RPS law was amended in 2006 to add provisions for penalties if the utility fails to meet its RPS requirements. In December 2007, the Commission issued a decision and order approving a stipulated RPS framework to govern electric utilities' compliance with the RPS law. In a follow

up order in December 2008, the Commission approved a penalty of \$20 for every MWh that an electric utility is deficient under Hawaii's RPS law.¹

Under the HCEI Agreement, the RPS goals would be substantially increased to 25% by 2020 and 40% by 2030, while eliminating energy efficiency and conservation entirely from consideration as contributors to the RPS targets after 2014. Furthermore, the HCEI Agreement includes a provision under which imported biofuel generation could not account for more than 30% of the RPS target through 2015.

The Hawaiian Electric Companies are committed to achieving these goals; however, due to risks such as potential delays in IPPs being able to deliver contracted renewable energy, it is possible the Companies may not attain the required renewable percentages in the future. To achieve these very aggressive goals, the Hawaiian Electric Companies will have to successfully negotiate acceptable PPAs with project developers that naturally want to shift risk to the utility and its customers, the project developers will have to be able to successfully finance, permit, construct, obtain fuel for (in the case of biomass projects) and maintain their projects, the Hawaiian Electric Companies and project developers will have to solve the problems inherent in integrating the projects into the utility grid, and the Companies will have to finance, permit and construct the infrastructure necessary to integrate the new resources into the grid.

As noted above, in order to meet their commitments under the HCEI Agreement (including the higher renewable portfolio standards), the Hawaiian Electric Companies will have to enter into numerous new PPAs for renewable energy. The long-term, fixed obligation nature of purchased power obligations negatively impacts the Hawaiian Electric Companies' credit

¹ The Commission noted, however, that this penalty may be reduced, in the Commission's discretion, due to events or circumstances that are outside an electric utility's reasonable control, to the extent the event or circumstance could not be reasonably foreseen and ameliorated, as described in the RPS law and in the RPS Framework.

quality. One measure of how investors view purchased power obligations is the "imputed debt" calculated by credit rating agencies. Although none of the Companies' existing PPAs appear on the Companies' balance sheet as long term obligations, credit rating agencies "impute debt" for these long term obligations.

In addition, the Companies will need to finance the infrastructure projects necessary to integrate these resources into the electric grid without negatively impacting service reliability. Infrastructure projects are capital intensive, and the Companies' current capital expenditure budgets are already significant given increased loads and the aging infrastructure on each system.

Thus, to achieve the objectives in the HCEI Agreement, as well as to meet normal service requirements, the Companies are anticipating substantial increases in actual debt (due to higher capital expenditures) and imputed debt (due to higher amounts of purchased power). The Companies also are faced with rapidly rising operations and maintenance costs, in addition to rising capital expenditures.

At the same time, the HECO Companies' credit ratings have been downgraded,² and adding to their capital requirements without demonstrating support for their timely ability to earn on and recover that investment would exacerbate that situation. Timely rate relief and mechanisms which align cost recovery with cost incurrence will improve the Companies' potential to realize actual financial results consistent with allowed returns.³

² In May 2007, Standard and Poor's ("S&P") downgraded HECO's corporate credit, unsecured debt and preferred stock ratings. HECO's current corporate credit rating of BBB is one notch above the minimum investment grade rating (BBB-). A further credit rating downgrade to the "BB" category or below would categorize HECO's debt issues as non-investment grade or "speculative grade" investments or "junk bonds".

³ The HECO Companies have numerous regulatory actions pending before the Commission that will impact the credit rating agencies' assessment of the Companies' regulatory risk. Regulatory decisions suggesting that the utilities will not have regulatory support increase the Companies' risk profile, and thus place into jeopardy the Companies' current credit ratings. Another downgrade of those ratings would increase the Companies' cost of capital, and thus, ultimately, the rates that customers are required to pay. Accordingly, the Companies must continue to obtain regulatory rulings that: (1) give the Companies a realistic opportunity to earn a fair return; (2)

The implementation of new cost recovery mechanisms incorporated in the HCEI Agreement (including the REIP surcharge, the purchased power clause and the RAM mechanism) is intended, in part, to help the Companies maintain their existing credit rating and investment risk profile, by helping the utilities to recover in a more timely fashion the costs of the infrastructure and other investments required to support significantly increased levels of renewable energy, and helping the Companies achieve fair rates of return. With respect to decoupling, the HCEI Agreement explicitly provides that:

The transition to Hawaii's clean energy future can be facilitated by modifying utility ratemaking with a decoupling mechanism that fits the unique characteristics of Hawaii's service territory and cost structure, and removes the barriers for the utilities to pursue aggressive demand-response and load management programs, and customer-owned or third-party-owned renewable energy systems, and gives the utilities an opportunity to achieve fair rates of return. (HCEI Agreement at 32)

None of the mechanisms would eliminate the need for the Companies to raise the additional capital required to fund the infrastructure projects. For example, the REIP Surcharge would provide the HECO Companies with a more timely recovery method for Commission-approved infrastructure projects after such approved projects are placed in service, but generally would not be a means of raising capital prior to the approved projects' installation and use.⁴

provide full cost recovery of prudently incurred costs on which the Companies' investors make no profit; (3) assure cost recovery of and on necessary capital investments; and (4) provide a fair return on prudent investments. In order to have a realistic opportunity to earn a return determined to be fair in a rate case, the Companies need cost recovery to align with cost incurrence because sales are not growing and, therefore, cannot offset the increases in costs.

⁴ Under traditional ratemaking, the Companies have to wait for rate cases to be processed to begin recovering costs incurred to install new infrastructure, which means there can be a substantial lag in recovering costs, and even substantial cost under-recovery which can result in credit degradation and a higher cost of capital, which ultimately is paid by the ratepayers. To help avoid this, traditional ratemaking should be supplemented with other ratemaking tools, such as the proposed REIP Surcharge, which would allow cost recovery to begin as soon as new facilities go into service.

S&P has the following view of cost recovery mechanisms which track RPS costs:

Also favorable for credit is the fact that statutory requirements that typically create RPS often require regulatory approval for the recovery of these costs in customer rates. Mechanisms that track RPS costs

Decoupling Details

Overall S&P views decoupling favorably, but it is not automatically considered good for credit quality. It appears to be viewed in the entire context of the various complex issues under consideration, including unintended consequences in establishing a decoupling mechanism. In the S&P's February 2008 article, "Decoupling: The Vehicle For Energy Conservation?"

(Attachment 2), S&P has indicated that:

Recent changes, including rising global warming concerns, and soaring commodity prices and building material costs, have brought decoupling to the forefront of the U.S. utility sector. To address some of the challenges, regulators are turning towards energy-efficiency programs and focusing on decoupling as the means for their implementation. In general, Standard and Poor's Ratings Services views decoupling as beneficial to the utilities' credit quality. Nevertheless, achieving energy conservation through decoupling may present risk and unforeseen challenges. (Attachment 2 at 2).

Also from the same article:

Standard & Poor's views decoupling as a positive development from a credit perspective....Standard & Poor's will only consider a decoupled mechanism good for credit quality if it minimizes the lag time before deferrals are included in rates, and does not subject the rate changes to a protracted prudence review. (Attachment 2 at 3.)

The article concludes as follows:

Overall, Standard & Poor's views decoupling as positive for the credit quality of a utility. However, there are many other complex issues that regulators and utilities must consider, including unintended consequences, when establishing a decoupling mechanism. During the past 25 years, some companies have executed a successful energy-efficiency program (i.e., Northwest Natural Gas Co. and Pacific Gas and Electric Co.) through the use of decoupling, while others have failed (i.e., Puget Sound Energy, Inc., and Central Maine Power Co.). As issues such as global warming continue to be part of the political landscape, increased focus on energy conservation appears inevitable, as well as the pressure for individual states to properly implement a decoupling mechanism to help facilitate conservation. (Attachment 2 at 8.)

for recovery from the customer, rather than incorporate RPS as part of general resource procurement, are, in our view, more credit protective for utilities, as are explicit RPS surcharges on customer bills that provide price transparency and distance the utility from charges that are state mandated.

In S&P's November 2008 report on HECO, the following is noted which reflects S&P's favorable view of decoupling and also S&P's view that decoupling is a critical component of the HCEI from a credit perspective:

To incentivize HECO to achieve these [energy] goals, the CEI [Hawaii Clean Energy Initiative] contemplates several protections that may support credit quality as the company transitions to this new model. These features include:

- Decoupling revenues from sales. This is critical component of the plan from a credit perspective. Without decoupling, HECO could expect to see lost revenues as its sales drop through energy efficiency and off-grid investments. Decoupling is to be implemented beginning with the interim decision in HECO's 2009 rate case, which is pending before the commission. HELCO and MECO will file 2009 rate cases to implement decoupling for these utilities. (Attachment 1 at 2.)

The S&P report on HECO also goes on to say that:

The CEI provides the framework and in places is specific on program design and implementation schedules. Nevertheless, some of the details of major provisions, including the structure of the CEIS [energy infrastructure surcharge], will be left to the commission to create on a timely basis. As a result, whether the CEI is ultimately credit-neutral for the company will depend on whether HECO is able to develop detailed implementation plans in partnership with the commission and stakeholders. For example, the commitment to decouple HECO's rates in the CEI appears to be tentative, as the CEI clearly allows the commission to discontinue decoupling if it is not "operating in the interest of ratepayers." (Attachment 1 at 2.)

Further, the following appears in the S&P article, "Top 10 Investor Questions for the U.S. Electric Utilities Sector in 2009" (Attachment 3):

Companies are implementing alternative energy sources such as wind and solar to meet mandated renewable standards. How quickly utilities can recover the 'green' that they spend to 'go green' will largely determine how they maintain credit quality. These expenses include all ancillary costs, including those for transmission upgrades and additional peaking units needed to back up renewable resources that are frequently intermittent in nature. (Attachment 3 at 2.)

...

Encouraging energy efficiency without recovery mechanisms burdens coverage ratio metrics. While customers are changing their consumption patterns, decoupling mechanisms allow utilities to recoup lost sales revenue. This helps mitigate cash flow pressures when usage goes down due to economic decline. (Attachment 3 at 3.)

- 7.1. If decoupling resulted in less overall financial risk for the utility, this could be taken into account in the estimation of the return on common equity in rate cases. However, any increased risks resulting from the HCEI initiatives would also need to be considered in determining the cost of common equity.
- 7.2. It is uncertain what effect, if any, decoupling would have on the beta of the utilities' comparable companies and how a change in beta would affect the utilities' return on common equity and what the capital structure implications might be.
- 7.3. It is not known whether input from the rating agencies can be obtained during the development of the decoupling process. Such input may be difficult to obtain. As noted above, however, overall S&P views decoupling favorably, but it is not automatically considered good for credit quality. It appears to be viewed in the entire context of the various complex issues under consideration, including unintended consequences in establishing a decoupling mechanism.

**STANDARD
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My Credit Profile

Hawaiian Electric Company, Inc., HI - 'BBB/Stable/A-2'

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Rationale
Outlook

Summary: Hawaiian Electric Co. Inc.

Publication date: 26-Nov-2008
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Rationale

The 'BBB' corporate credit rating assigned to Hawaiian Electric Co. Inc. (HECO) reflects the consolidated credit quality of HECO and its holding company, Hawaiian Electric Industries (HEI), whose operations are limited to the ownership of HECO and American Savings Bank (ASB; 'BBB'). HECO's 'strong' business profile reflects its ownership of regulated utility assets, which serve about 95% of Hawaii's population. HECO's credit quality benefits from an exclusive franchise to serve retail electric customers, a strong fuel and purchased power recovery mechanism, and an adequate regulatory environment whose framework has the potential to change significantly with recently announced plans to revamp energy policies on the island (discussed below). Key challenges to HECO's ratings include the execution of such plans and the impacts on the company's financial performance as function of the weakening in the Hawaii economy. The island economy is highly dependent on a limited number of industries, including tourism and construction, and local economic indicators have begun to show signs of deterioration.

The consolidated financial profile is 'aggressive', reflecting in part the very heavy debt imputation Standard & Poor's Ratings Services applies to HECO for its long-term power purchase agreements (PPAs). These obligations added about \$469 million in on-balance-sheet debt 2007 and about \$568 million beginning in March 2008 and reflect evergreening of PPA obligations. (Consistent with our published criteria, we assume that expiring PPA contracts are replaced with new ones at similar terms.) While we apply significant debt obligations to HECO, we also recognize the historical reasons that have led to HECO buying a substantial amount of its power supply from third-party suppliers and that the regulatory recovery of capacity costs associated with these contracts has been supportive. Thus, our 'BBB' ratings reflect consideration of the unique size of these obligations.

HECO serves Oahu; Maui Electric Co. (MECO) serves Molokai, Lanai, and Maui; and Hawaiian Electric Light Co. (HELCO) serves The Big Island of Hawaii (The utilities do not serve the island of Kauai, where electric service is provided by a cooperative.) Consolidated reported debt outstanding at HEI as of Sept. 30, 2008, was \$1.21 billion (excluding bank borrowings), and is principally composed of HECO, MECO, and HELCO unsecured debt that totaled of \$904 million as of the same date. HEI also has \$307 million of unsecured medium-term notes to support parent and utility operations. Bank borrowings are managed by ASB at the operating level.

In October the company entered into a massive energy policy agreement that will transform how the islands procure electricity and what role HECO plays in procurement and new generation construction. The Hawaii Clean Energy Initiative, or CEI, was signed by the state's governor; the State of Hawaii Department of Business, Economic Development, and Tourism; the Division of Consumer Advocacy of the State of Hawaii Department of Commerce and Consumer Affairs; and Hawaiian Electric Co. Inc. The CEI sets forth ambitious energy goals that include:

- Introducing legislation that will increase renewable portfolio standards to 25% by 2020 (the goal now is 20% now) and 40% in 2030 (a new standard);

- Pursuing the integration of approximately 1,100 MW of renewable energy sources, with 700 MW to be implemented within five years;
- Constructing an undersea cable connecting Maui, Molokai, and Lanai into one electrical grid to allow the integration of an additional 400 MW of renewable wind power;
- Converting HECO's existing fossil-generation to biofuel, with preferential purchasing provided to local fuel suppliers;
- Installing advanced meters to implement time-of-use rates that reward customers with lower electric rates for using power during off-peak times;
- Eliminating existing systemwide caps on net energy metering to allow customers to produce their own renewable energy and obtain bill credits for excess generation;
- Implementing an energy efficiency portfolio standard, with administration of planned programs shifting to a third party, rather than the utility; and
- Creating a feed in tariff by mid-2009 to promote distributed, smaller-scale renewable generation such as solar photovoltaics.

To incentivize HECO to achieve these goals, the CEI contemplates several protections that may support credit quality as the company transitions to this new model. These features include:

- Decoupling revenues from sales. This is a critical component of the plan from a credit perspective. Without decoupling, HECO could expect to see lost revenues as its sales drop through energy efficiency and off-grid investments. Decoupling is to be implemented beginning with the interim decision in HECO's 2009 rate case, which is pending before the commission. HELCO and MECO will file 2009 rate cases to implement decoupling for these utilities.
- Creating an energy infrastructure surcharge (CEIS) to recover costs. The CEIS would reset annually and is designed to recover HECO's infrastructure investment required to support the program. HECO may also use the CEIS to recover any costs stranded because of the CEI. This is favorable as it provides the company with a clear mechanism for cost recovery and provides for annual adjustments.
- Providing HECO with the opportunity to get construction work in progress (CWIP) treatment. HECO may file for CWIP, which the commission would need to approve on a project-by-project basis.
- Funding energy efficiency programs through a public benefit charge that will be initially set at 1% of utility total revenues in the first two years, rising thereafter. Administration of energy efficiency programs will be shifted to a third party. This is a benefit for credit quality as it clearly delineates the costs of achieving energy efficiency on the company bill and provides a funding vehicle for the programs.

The CEI provides the framework and in places is specific on program design and implementation schedules. Nevertheless, some of the details of major provisions, including the structure of the CEIS, will be left to the commission to create on a timely basis. As a result, whether the CEI is ultimately credit-neutral for the company will depend on whether HECO is able to develop detailed implementation plans in partnership with the commission and stakeholders. For example, the commitment to decouple HECO's rates in the CEI appears to be tentative, as the CEI clearly allows the commission to discontinue decoupling if it is not "operating in the interest of ratepayers."

Credit concerns around the CEI focus on three areas: the feasibility of the plan and what the ramifications are for HECO if it cannot meet the ambitious program outlined in the CEI, the costs of CEI and whether ratepayers will ultimately be willing to bear them, and the potential impact on reliability.

The level of renewable, energy-efficiency, and distributed-generation investment is significant. Just focusing on HECO (e.g., excluding goals for MECO and HELCO) the CEI would require 148 MW of renewable installed by 2010, jumping to 890 MW by 2015. Similarly for energy efficiency and distributed generation goals, 169 MW of measures would need to be in place by 2010, rising to 1,015 MW by 2015. There are also concerns related to the feasibility of sourcing the level of biofuel that HECO will require. Notably, the CEI does not include penalties for noncompliance with the CEI; we would expect this issue to be taken up in future regulatory proceedings.

It is unclear what the cost ramifications of such a program are and how it would compare with the state maintaining its very high dependence on petroleum oil to meet energy needs. The majority of electric power generated in Hawaii is produced through burning imported liquid fossil fuels. Fuel oil comprises around 77% of the three utilities' power supply portfolio. From a ratings perspective, this has not been a significant issue because a monthly fuel and purchased power adjuster has allowed the utility to stay

current on its fuel recovery despite gyrations in the price of oil.

But in 2008, customers have seen significant electric bill increases with increasing oil prices in the first half of the year. Rate impacts caused by oil prices, which HECO cannot control, are inevitably a public relations issue for the company that is difficult for it to manage. But given the current state of renewable technology and the cost of biofuel, the CEI implicitly requires Hawaii's residents to trade off higher electric costs for less rate volatility. This is particularly true over the next few years if oil prices continue in their decline as a function of recessionary pressures. Hawaii already pays some of the highest rates in the U.S. On the other hand, the plan may assist the state in managing the costs of carbon regulation. Rating implications will focus squarely on the retail rate impacts of the initiative over time.

Electric system reliability will also need to be a major consideration going forward, as the issues presented by integrating substantial intermittent solar, wind, and distributed-generation resources is not trivial. Moreover, HECO's long-term commitment to the HECO not to build more biofuel generation without incremental retirement of the existing resources raises issues of how it can reliably meet load growth, especially in the event that energy efficiency initiatives are lagged. Reserve margin issues have been an ongoing concern in parts of the islands.

Also of interest is the state's intention to develop an undersea transmission cable as part of the CEI to bring to Oahu wind power from to-be-constructed large-scale projects developed on other islands. (The majority of the population resides on Oahu but wind resources are poor there.) Despite the fact that CEI clearly tasks the state or a third party to undertake the development, construction, and operations of an undersea cable, the initiative contemplates that HECO might be a co-partner in financing, and could possibly issue debt to support the project. The details on any such arrangement would be important to credit quality, as HECO's balance sheet may not be able to withstand a large infrastructure investment of this type. HECO's consolidated debt profile already reflects significant leverage, in part due to our PPA debt imputation. The CEI contemplates the company issuing preferred stock and hybrid offerings to fund clean energy initiatives as a strategy to avoid the full impact of additional debt on the balance sheet. We would note that aggressive use of hybrid or preferred offerings would likely lead to adverse rating consequences.

The next few years are likely to be pivotal for company credit quality, as the CEI program details will likely shape the company's financial position for years to come. We would note that going into the CEI, the company is not well positioned financially. HEI's results were notably poor in 2007-- resulting in lower consolidated financial metrics -- due to the need for sizable interim rate relief, which was granted by the Hawaii Public Utilities Commission in late 2007 and began to improve ratios modestly in 2008. Consolidated financial performance for HEI on a trailing 12-month basis ended Sept. 30, 2008, was 13.5% funds from operations (FFO) to total debt, and 3.3x FFO interest coverage. Debt to total capitalization is 61.5%, which reflects consolidated HEI operations.

We would expect 2009 results to be dampened by a slowing economy, which is expected to depress electric sales. (Notably, any decoupling benefits the company may expect to see through the CEI are not likely to be implemented before late 2009 or early 2010.) After months of not showing sizable economic weakening relative to the mainland, Hawaii's major economic indicators are reflecting a significant slowdown that began in mid-summer. According to the state's tourism authority, visitor arrivals and visitor days fell 9.1% and 7.6% year-to-date, respectively, compared with the same period in 2007. The authority predicts visitor arrivals and visitor days will continue to decline 10.1% and 9.7%, respectively, for the full year 2008 and further decline by 1.9% and 1.7% in 2009; recovery will not begin until 2010. Visitor expenditures also fell 7% during the same period. Construction activities have also slowed down. Hawaii's unemployment rate of 4.5% at the end of September 2008 continues to remain below the national average of 6.1%. However, the decline in tourism is expected to result in further job losses in the next year.

This softening in the economy, together with high prices of fuel oil year to date and conservation, has led to a 1.2% year-to-date reduction of kilowatt-hour of sales, which management has publicly estimated to have reduced earnings by \$4 million after-tax for the nine months ended Sept. 30, 2008. We expect this downward trend to continue going into 2009 and believe that the decline in sales volume could impact the company's results of operations.

On the rate case front, all three utilities are awaiting final orders on interim rate relief award. HECO has been awarded interim relief of \$70 million based on its 2007 test year rate case, HELCO has been awarded \$25 million based on a 2006 test year rate case, and MECO has been awarded \$13 million in its

2007 test year rate case. Also, in July 2008, HECO filed a request for a general rate increase of \$97 million – 5.2% over the current rates – based on a 2009 test year, an 8.81% rate of return, an 11.25% return on average capital employed, and a \$1.41 billion rate base. HECO's application requested an interim increase of \$73 million on or before the statutory deadline for interim rate relief and a step increase of \$24 million based on the return on net investment of the new combustion turbine generating unit and recovery of associated expenses to be effective at the in-service date of the new unit, scheduled for the end of July 2009. HECO's application will be expanded to address decoupling.

Short-term credit factors

The short-term corporate credit and commercial paper (CP) rating on HEI and HECO is 'A-2'. HEI and HECO's liquidity has been strained as a function of increased short-term debt balances to support capital expenditures. Given substantial deterioration in the credit markets, we would expect the company in the next quarter to make efforts to increase its cash and available credit position through equity, debt issuances, or via a new credit line facility as a defensive measure.

HEI and HECO have credit facilities of \$100 million and \$175 million, respectively. As of Sept. 30, 2008, HEI had only \$10 million in remaining capacity on its line (assuming capacity for CP balances is reserved in the event of disruption in this market). HECO had \$34 million. While consolidated cash and cash stood at \$166.7 million as of Sept. 30, 2008, most of this cash, about \$128 million, resides at ASB, and bank regulations would require certain tests to flow cash to HEI. HEI's cash balances are estimated to be \$23.6 million, which include HECO's \$14.8 million. Thus, total liquidity as of Sept. 30 is less than \$65 million.

The company had exposure to \$15 million in its credit facilities, but in the third quarter these obligations were assigned to the Bank of Hapoalim BM. HEI and HECO do not face any remaining maturities in 2008 or 2009. Both HECO and HEI's unsecured revolving credit line expire on March 31, 2011.

Outlook

The stable outlook reflects our expectation that, for now, HECO appears to have reasonable but not certain prospects for maintaining its existing financial profile, which is weak for the rating. Multiple near-term challenges face the company and include the uncertainties of the cost and feasibility impacts of the CEI, the potential for a significant reduction in electric sales in 2009 (due to economic contraction, energy efficiency initiatives, and customer response to high prices), and a recent softening in leading economic indicators. These challenges suggest that a negative outlook or downward revision to the ratings could be possible over the outlook horizon, as further weakening in the financial profile will not support ratings, and near-term business risk will be elevated until the particulars of the CEI are in place and prove to be supportive. Consistent, timely rate relief will continue to be key, and could offset or mitigate the effects of a declining economic environment, but decoupling or other measures are not expected to be available to the company before late 2009 or early 2010. Given these challenges, higher ratings are not foreseen during the outlook horizon and would need to be accompanied by sustained and improved financial performance.

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Decoupling: The Vehicle For Energy Conservation?

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Decoupling: The Vehicle For Energy Conservation?

Although decoupling rate mechanisms have been in effect since the early 1980s, they were initially introduced only on a limited basis. Recent changes, including rising global warming concerns, and soaring commodity prices and building material costs, have brought decoupling to the forefront of the U.S. utility sector. To address some of the challenges, regulators are turning towards energy-efficiency programs and focusing on decoupling as the means for their implementation. In general, Standard & Poor's Ratings Services views decoupling as beneficial to the utilities' credit quality. Nevertheless, achieving energy conservation through decoupling may present risks and unforeseen challenges.

Traditional Rate Mechanism

Utility regulators have historically set electricity rates that allow the utility to recover its operating costs and earn a return on equity. Once the new rate is realized, it will remain in effect until the completion of a subsequent rate case. During the interim period, a utility's actual distribution revenues earned may fluctuate from the amount forecasted due to changes in the weather and the regional economy. For example, if the weather is warmer than expected, customers will use more kilowatt-hours (kWh) and the utility will earn more distribution revenue than was previously forecasted. Conversely, if there is an economic downturn, customers will use less kWh and the utility's actual revenues would be less than projected.

Under the traditional rate mechanism, every kWh sold adds to a utility's profits and every kWh lost due to conservation reduces profits. Thus, a utility's traditional response to higher electric demand was to increase its rate base by adding generation. There was no incentive to lower demand through an energy-efficiency program. This can be especially frustrating to both the utility and to its customers when the most cost-effective solution is to reduce demand rather than to increase supply. To attempt to resolve this inherent conflict, regulators and utilities have turned to decoupling.

Is Decoupling The Solution?

Decoupling is a mechanism that severs the relationship between sales and revenues, thereby allowing a utility to earn a predetermined level of distribution revenue regardless of the actual kWh sold. There are several variations as to how decoupling is computed, including normalizations for weather and number of customers, and caps for maximizing the rate adjustment. Still, its basic principle is that a true-up mechanism is applied to actual sales, allowing the utility to earn a predetermined level of distribution revenue. Similar to traditional rate mechanism, decoupling charges customers based on rate per kWh, but adjusts the rate to ensure that the predetermined distribution revenue is earned. By using a decoupled rate mechanism, the utility is indifferent as to the amount of kWh customers consume. This mechanism removes the disincentive for utilities to conserve, and allows a utility to execute an energy plan of either supply growth or demand reduction based on solid economics and/or other policy issues. Other potential benefits for decoupling include the following:

- Fewer rate cases filings, which result in lower overall costs for the utilities;
- Reduced need for new power plants whose costs have skyrocketed during the past five years; and

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- Overall lower customer bills due to energy conservation.

However, decoupling on its own doesn't guarantee that a utility will implement a successful energy-efficiency program; it only ensures that a utility is indifferent as to the customer's usage. To persuade a utility to actively and successfully implement an energy-efficiency program, some regulators have established a separate program that provides penalties and incentives for meeting certain energy-efficiency standards. For example, Arizona Public Service Co. has \$10 million annually in base rates for energy efficiency and the utility may earn an incentive of up to 10% of the net economic benefits based on its energy-efficiency performance.

Credit Implications Of Decoupling

Standard & Poor's views decoupling as a positive development from a credit perspective. Decoupling allows utilities to project cash flow more accurately and avoid much of the earnings volatility from changes to weather/economy under traditional rate mechanisms. To decouple sales and revenues, most regulators use a tracking mechanism, such as a balancing account, to record deviations from the financial projections. Standard & Poor's will only consider a decoupled mechanism good for credit quality if it minimizes the lag time before deferrals are included in rates, and does not subject the rate changes to a protracted prudence review.

Nevertheless, decoupling has not been widely adopted due to the following factors:

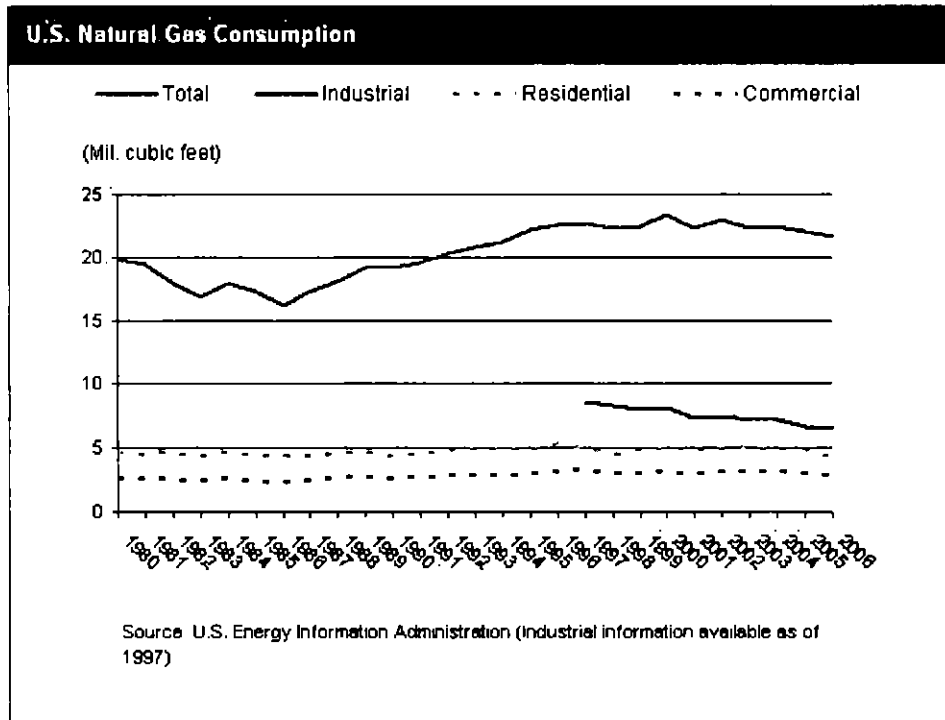
- Some utilities prefer the traditional rate mechanism, which provides for a windfall when the weather is hotter than normal;
- Decoupling may shift the risk of sales volume variations associated with weather/economy from the utility to the customer;
- Regulators may require a lower ROE in exchange for decoupling's reduced risks;
- Decoupling's guaranteed level of distribution revenue, regardless of actual performance, may promote mediocrity in the management of a utility and cause a decline in customer service; and
- Previously failed decoupling experiences.

Gas Decoupling More Prevalent

Regulators have approved and implemented decoupling mechanisms for gas utilities in 11 states and for electric utilities in only three states. This discrepancy can be traced to the per-customer usage of each commodity (see charts 1 and 2). Natural-gas use per customer has been in decline since the 1980s due to the improvement in housing insulation, the installation of efficient gas boilers, and global warming.

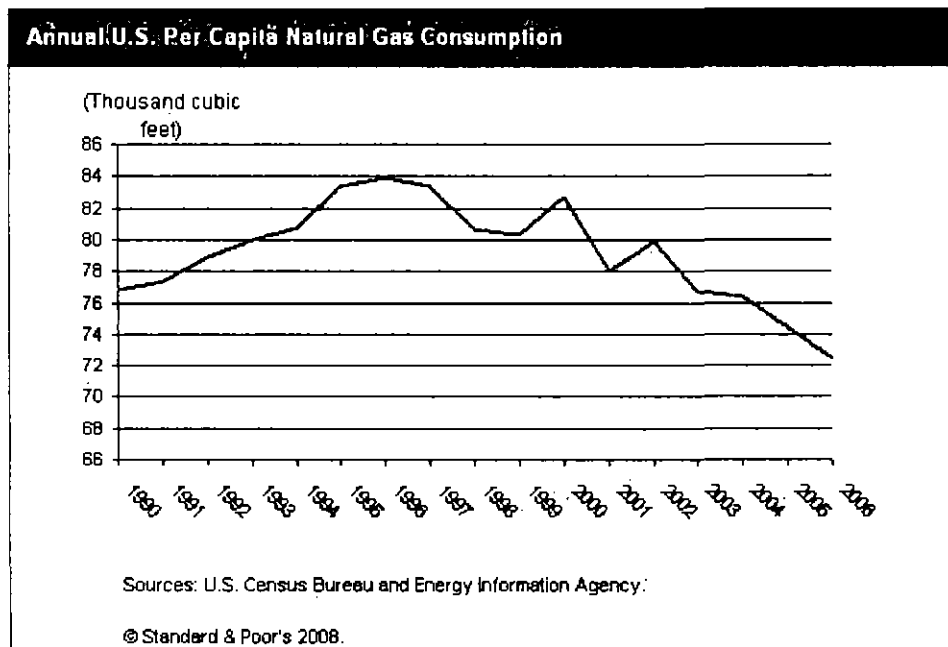
Decoupling: The Vehicle For Energy Conservation?

Chart 1



Decoupling: The Vehicle For Energy Conservation?

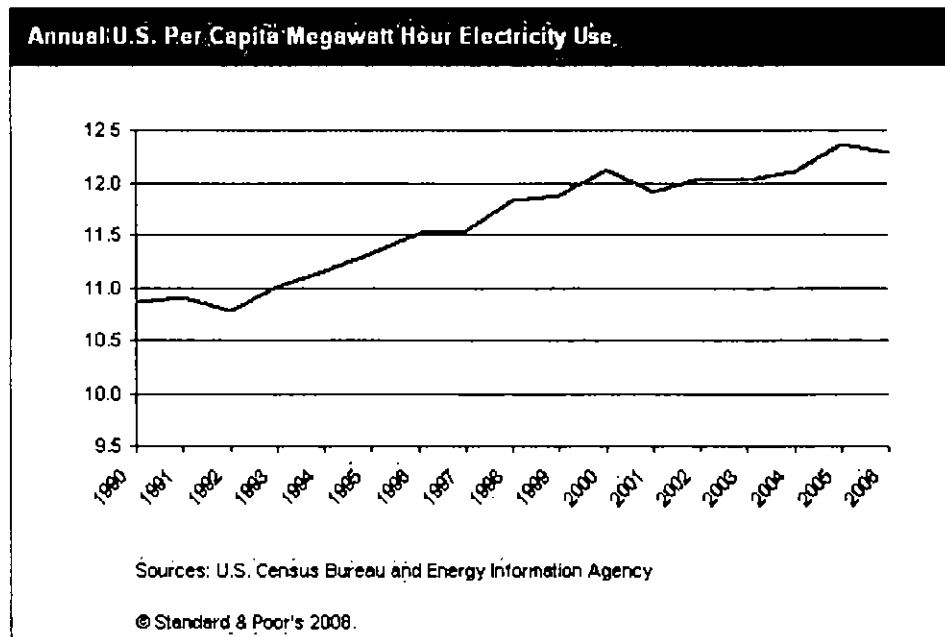
Chart 2



Electricity use per customer, for the most part, has increased over the same period (see chart 3). Despite the availability of energy-efficient air conditioners, refrigerators, and light bulbs, electric use per customer has risen due to larger homes and greater use of technology.

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Chart 3



To help offset the earnings loss due to energy efficiency, gas utilities have been working with regulators to establish a decoupling mechanism. On the other hand, electric utilities may potentially face lower earnings due to decoupling because they would have to forgo the potential benefits of warmer weather or an upturn in the economy.

Decoupling's Pros and Cons

Some decoupling mechanisms isolate the kWh consumption changes solely from energy efficiency and are not affected by energy changes due to the weather/economy. These types of decoupling mechanisms effectively preserve the status quo that the risk of weather/economy remains with the utility. For example, the Illinois Commerce Commission recently approved a gas decoupling mechanism for the Peoples Gas Light and Coke Co. that provides a credit/charge to customers when the weather varies from normal and theoretically retains the risk of weather with the utility. However, these mechanisms can be complex and for the most part, many of the existing decoupling models are directly affected by changes to weather/economy and thereby shift those risks to the customer from the utility. Reacting to this shift in risk, advocacy groups and regulators have requested that customers be compensated in the form of a lower authorized ROE for utilities. These basic changes to historical risks and assumed returns have been partially attributable for the resistance towards implementing a decoupled rate mechanism.

Maine

Another setback for decoupling has been some of the past failures of its implementation. In the 1990s, Maine introduced a decoupling mechanism that led to an abrupt rise in electricity rates, and the state ultimately abandoned the program. The steep rate hike was due to the recession, rise in deferred balances over an extended period instead of a periodic true-up, and no cap on the rate increase. This and other similar experiences point to the potential risks

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involved when implementing a decoupled mechanism and its unintended consequences.

California

California is the most successful example of the use of a decoupling mechanism. California first set up decoupling in 1982 and has subsequently combined it with various energy-efficiency incentive programs. This has led to today's per capita use of electricity in California to be virtually the same as in the 1980s and compares favorably to the significant increase of per capita electricity usage for the rest of the country. As of 2006, California had the lowest per capita use of electricity in the U.S. (see table). California was able to achieve these results by making energy efficiency a top priority and requiring utilities to invest in energy efficiency whenever it was cheaper than procuring power. In addition, the state successfully collaborated with businesses, non-profit organizations, government agencies, and utilities to work together to implement conservation solutions. California is clearly the best example of how implementing a decoupling mechanism can be an integral part of the overall conservation package.

Annual Per Capita Megawatt Hour Electricity Use*																	
	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006
Wyoming	25.9	25.6	25.1	25.1	24.4	23.1	23.5	24.1	23.7	24.0	25.0	26.3	25.9	26.5	26.9	27.9	29.1
Kentucky	16.5	17.2	17.8	17.9	18.8	19.2	19.6	19.4	19.0	19.7	19.3	19.7	21.3	20.7	20.9	21.4	21.1
Alabama	14.8	14.9	15.0	15.4	15.9	16.3	16.9	17.1	18.0	18.1	18.8	17.8	18.6	18.7	19.3	19.6	19.8
District of Columbia	16.3	17.0	16.8	17.4	17.5	17.8	17.7	17.8	18.2	18.3	18.6	18.8	19.2	19.0	19.7	20.3	19.5
South Carolina	15.9	16.0	16.1	16.8	16.7	17.4	17.7	17.8	18.5	18.4	19.1	18.4	19.0	18.6	19.0	19.1	18.7
Louisiana	15.1	15.2	15.2	15.7	16.1	16.6	17.1	17.2	17.5	17.5	18.1	16.7	17.7	17.4	17.8	17.2	18.3
West Virginia	12.9	13.1	13.2	13.4	13.6	14.2	14.3	14.4	14.6	15.0	15.3	15.4	15.8	15.7	16.0	16.7	17.9
North Dakota	11.0	11.4	11.2	11.6	11.9	12.7	12.8	12.7	12.7	14.1	14.7	15.4	16.1	16.5	16.5	17.0	17.6
Tennessee	15.8	15.8	15.6	15.5	15.8	15.4	16.2	15.8	16.5	16.5	16.8	16.7	16.9	16.6	16.9	17.3	17.1
Indiana	13.3	13.7	13.6	14.3	14.5	14.9	15.1	15.0	15.3	16.0	16.1	16.0	16.5	16.2	16.6	17.0	16.8
Arkansas	11.6	11.9	11.8	12.9	13.1	13.7	14.0	14.2	15.0	15.0	15.5	15.5	15.7	15.8	15.9	16.7	16.6
Mississippi	12.5	12.7	12.7	13.1	13.6	13.9	14.4	14.4	15.2	15.5	15.9	15.5	15.9	15.9	15.9	15.8	16.2
Idaho	17.8	17.3	17.7	16.0	17.4	16.7	18.1	18.2	17.6	17.8	17.6	16.0	15.4	15.6	15.7	15.3	15.5
Nebraska	11.3	11.7	11.0	11.5	12.1	12.6	12.8	13.4	13.6	13.4	14.2	14.4	14.9	14.9	14.8	15.4	15.5
Oklahoma	13.5	12.4	11.9	12.5	12.5	12.5	13.0	13.2	14.1	13.6	14.3	14.3	14.2	14.4	14.5	15.2	15.3
Texas	13.9	13.8	13.5	13.8	13.9	13.9	14.4	14.5	15.1	14.7	15.2	14.9	14.8	14.6	14.3	14.6	14.6
Montana	16.4	16.6	15.9	15.3	15.3	15.3	15.6	13.4	15.8	14.8	16.1	12.6	14.1	14.0	14.0	14.4	14.6
Iowa	10.6	11.0	10.7	11.3	11.6	12.0	12.2	12.5	12.9	13.0	13.3	13.5	14.0	14.0	13.9	14.5	14.6
Georgia	12.4	12.3	12.2	12.8	12.8	13.1	13.5	13.3	14.1	14.0	14.5	14.0	14.4	14.2	14.5	14.5	14.4
Kansas	10.9	11.3	10.7	11.3	11.5	11.7	12.0	12.2	12.8	12.6	13.3	13.3	13.5	13.5	13.6	14.2	14.4
North Carolina	13.5	13.6	13.7	14.2	13.9	14.3	14.4	14.2	14.5	14.5	14.8	14.5	14.7	14.4	14.7	14.8	14.3
Missouri	10.5	10.9	10.4	11.1	11.2	11.6	11.9	12.0	12.5	12.4	13.0	13.0	13.2	13.0	12.9	14.0	14.0
Virginia	11.7	11.0	11.9	12.5	12.5	12.8	13.0	12.8	13.1	13.3	13.6	13.4	13.8	13.8	14.1	14.4	14.0
Nevada	13.4	12.8	13.1	13.1	13.4	13.1	13.5	13.7	13.5	13.6	13.8	13.4	13.5	13.5	13.4	13.5	13.9
Delaware	12.4	12.5	12.3	12.9	13.0	13.1	13.0	13.5	13.6	13.6	14.3	14.3	14.9	15.4	14.2	14.4	13.5
Ohio	13.1	13.3	13.1	13.4	13.8	14.2	14.1	14.1	14.1	14.5	14.5	13.7	13.4	13.3	13.5	14.0	13.4
Washington	18.6	18.4	17.3	17.1	16.2	16.1	15.9	16.0	16.4	16.9	16.3	13.1	12.4	12.8	12.9	13.3	13.3
Oregon	15.0	14.9	14.3	14.6	14.4	14.4	14.9	14.7	14.0	14.0	14.7	13.2	12.9	12.7	12.7	12.8	13.0
Minnesota	10.7	11.0	10.5	10.8	11.1	11.6	11.7	11.7	11.8	11.8	12.1	12.2	12.4	12.5	12.5	12.9	13.0

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Annual Per Capita Megawatt Hour Electricity Use*(cont.)																	
South Dakota	91	95	91	96	98	100	104	104	105	106	110	114	117	118	119	126	128
Florida	110	109	108	110	112	115	116	115	121	119	122	123	126	128	126	127	126
Wisconsin	100	103	101	105	108	112	112	114	117	119	121	121	123	123	123	127	125
USA	109	109	108	110	112	113	115	115	118	119	121	119	120	120	121	124	123
Arizona	113	110	111	109	111	110	114	115	114	115	118	117	115	115	117	117	119
Pennsylvania	96	97	97	99	101	103	104	105	106	105	109	110	114	114	116	120	118
Maryland	103	105	104	108	109	111	111	109	111	112	114	115	126	130	121	123	113
Illinois	97	101	96	100	102	105	104	104	107	107	108	109	110	108	110	114	111
New Mexico	91	91	90	91	94	95	98	99	101	100	103	102	104	103	105	108	110
Michigan	88	90	88	92	95	98	99	99	102	105	105	102	104	108	106	109	107
Colorado	93	93	91	91	93	92	95	95	96	96	99	100	102	102	101	103	104
Utah	89	89	90	89	91	92	96	96	96	99	103	101	100	101	101	100	102
Maine	94	92	93	96	93	93	94	95	92	94	95	95	88	92	94	94	93
Vermont	84	83	86	87	87	87	88	89	89	91	92	91	91	87	92	95	93
New Jersey	81	83	80	83	83	83	82	80	82	85	83	86	87	89	90	95	92
Alaska	77	75	74	73	75	77	79	79	82	85	85	86	85	85	87	88	91
Connecticut	83	82	82	82	85	84	85	85	86	88	88	89	90	92	93	95	91
Massachusetts	75	74	75	75	76	76	77	77	78	78	81	82	84	86	87	89	87
New Hampshire	81	79	80	78	78	78	78	77	77	81	82	82	82	86	85	86	85
Hawaii	75	75	75	74	75	77	78	77	76	78	80	80	81	84	86	83	83
New York	72	71	70	71	71	70	71	71	72	74	75	76	77	75	75	78	74
Rhode Island	64	63	63	65	65	65	65	66	67	69	69	70	71	73	74	75	73
California	70	68	69	67	68	67	68	70	72	70	72	72	67	69	71	71	73

* Sorted based on 2006 data

Sources: U.S. Census Bureau and Energy Information Agency

Overall, Standard & Poor's views decoupling as positive for the credit quality of a utility. However, there are many other complex issues that regulators and utilities must consider, including unintended consequences, when establishing a decoupling rate mechanism. During the past 25 years, some companies have executed a successful energy-efficiency program (i.e., Northwest Natural Gas Co. and Pacific Gas and Electric Co.) through the use of decoupling, while others have failed (i.e., Puget Sound Energy Inc., and Central Maine Power Co.). As issues such as global warming continue to be part of the political landscape, increased focus on energy conservation appears inevitable, as well as the pressure for individual states to properly implement a decoupling mechanism to help facilitate conservation.

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RESEARCH

Credit FAQ:

Top 10 Investor Questions For The U.S. Electric Utilities Sector In 2009

Publication date: 23-Jan-2009

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(Editor's Note: In the article published Jan. 22, 2009, we erroneously stated that CenterPoint Energy Inc. had issued a common equity offering. In fact, CenterPoint Energy Houston Electric LLC had issued \$500 million in bonds. A corrected version follows.)

Standard & Poor's Ratings Services' forecast for the U.S. electric sector is for a stable ratings trend. The recession will continue to pressure cash flows and debt balances, but we expect most companies to weather 2009. Our forecast is backstopped by expectations of responsive regulatory decisions and continued access to debt and equity markets, which should provide sufficient cushion to maintain stability for the majority of companies. Those companies that fare poorly in the regulatory arena and experience significant deterioration in cash flow metrics and creeping debt leverage are most vulnerable to downward actions. Substantial capital spending needs and the potential for incremental costs to implement the Obama Administration's energy priorities limit upward ratings for the sector.

The following questions and answers are a representative sample of the credit issues that electric utilities will face in the coming year, including the weak economic environment, a drop in customer usage, delayed capital expenditures, costlier debt financing, and impending energy policy.

Frequently Asked Questions

Do you expect electric utilities to continue to have access to capital markets throughout 2009?

Credit ratings for the regulated electric sector incorporate our expectations that it can tap currently constricted capital markets. Challenging conditions that tested electric utilities' resiliency in 2008 included an unexpected contraction in short-term funding sources, loss of some banking syndicate members including Lehman Brothers Holdings, and an intermittent lack of investor appetite for even lower risk utility debt. Utility managements took some prudent financial steps in 2008, including increasing the size of credit facilities and prefunding debt maturities before the financial distress gained steam during the year.

For 2009, the electric utility sector is well positioned to benefit from possible investor demand for debt instruments issued by established market names with a good performance record and sustained investment-grade credit quality. Of course, investors are demanding higher coupons to complete deals with tenors ranging between five and 10 years; notably covenant protection has not been required to date outside of existing first mortgage bond indentures. Standard & Poor's expects that the most liquid of instruments will continue to be utility first mortgage bonds, which are backstopped by the utilities' physical plant and robust recovery prospects.

Although the economic slowdown may mute the need for debt issuance associated with building new plants, market activity is occurring. Some companies completed several debt offerings in January, including PacifiCorp's \$1 billion issuance of first mortgage bonds with a 10-year tranche at 5.5% and a 30-year tranche at 6% and CenterPoint Energy Houston Electric LLC's \$500 million general mortgage bonds with a five-year maturity at 7%. In addition, Progress Energy Inc. and PEPCO Holdings Inc. have strengthened their balance sheets in recent months with common equity offerings.

What types of regulatory challenges are at the forefront in 2009?

During this recession, regulators may come under pressure to dampen rate hikes. This creates a quandary for regulated electric utilities that plan their spending several years in advance. The companies' have initially responded to the recessionary slowdown by pulling back on 2009 spending. However, this can be viewed only as a stop-gap measure. Continued reliance on this strategy for a prolonged period could heighten the perception of reliability deterioration. Several companies expect rate decisions during the first quarter of 2009, including Union Electric Co. in Missouri, American Electric

Power Co. Inc.'s Ohio units, Southern California Edison Co., and Idaho's IDACORP Inc., and we'll be looking out for how the companies deal with declining electricity sales due to the recession. Regulatory bodies that defer prudently incurred costs during a period of declining electricity sales could harm credit quality.

During the past five years, regulated electric utilities and their ratepayers have benefited from historically low interest rates and cost of capital. Clearly, the pendulum swung back toward the mean in 2008; current rates of 500 basis points over Treasuries for 10-year 'BBB' debt (e.g., Metropolitan Edison Co.'s \$300 million unsecured notes) reflect this market reevaluation. Most utilities are operating under an authorized cost of debt that in some instances falls well short of actual debt pricing in today's marketplace. Standard & Poor's expects that regulators will begin reflecting the "new" cost of debt in customer rates. Regulators' willingness to recognize the higher cost of capital through overall returns is important for credit quality.

The changes in Washington in 2009 provide the Federal Energy Regulatory Commission (FERC) with an opportunity to reshape interpretation of energy policy. A re-emphasis on regulation in all industries may lead to more intervention by the FERC.

How will the new Administration's potential energy policy affect credit ratings?

At this stage, it is uncertain what credit challenges electric utilities will face under a new energy plan. Lower prices for crude oil and other commodities, combined with the depth of the recession, have likely pushed back the starting line. It will be interesting to see if the Obama Administration will propose substantial energy policy changes in its first 100 days. As the bartering in Congress begins, coal and new nuclear plants are endangered, and solar and wind are the rage. Comments by some Obama appointees indicate that coal, at least in a cleaner form, and maybe a few new nuclear plants, may have a place at the table.

What is certain is that the industry is changing. Companies are implementing alternative energy sources such as wind and solar to meet mandated renewable standards. How quickly utilities can recover the "green" that they spend to "go green" will largely determine how they maintain credit quality. These expenses include all ancillary costs, including those for transmission upgrades and additional peaking units needed to back up renewable resources that are frequently intermittent in nature.

Reducing carbon emissions in some form or manner, an Obama campaign promise, could affect ratings, depending on how ready, willing, and able local regulators are to allow utilities to pass along federally mandated costs to their customers. Companies were able to pass through previous costs for environmental standards to ratepayers, but at amounts much lower than a potential carbon tax or trading scheme. Just how—and how long it takes—companies to implement their carbon emission reduction will also factor into ultimate credit quality.

How important is liquidity for regulated electric utilities?

As we saw in the fourth quarter of 2008, electric utilities benefit greatly from ample liquidity. Having the ability to meet maturities eases refinancing pressures and exudes confidence to investors. This backstop allowed electric utilities to maintain access to the bond market during 2008 in all market conditions. Strong liquidity positions are a factor that bolsters electric utilities' credit profiles.

Several utilities faced significantly higher collateral calls in second-half 2008 due to sharply falling commodity prices. In some cases, collateral calls, combined with pending maturities, led to a somewhat urgent need to add additional liquidity facilities. It's important that those facilities are big enough to address future volatility in commodity prices.

Companies whose facilities expire later in 2010 and into 2011 will have to renew them at more burdensome terms. In the past, utility credit facilities have been unsecured, but that may change in the future. In addition, banks are introducing pricing based on credit default swaps for some industries, including utilities. Standard & Poor's has commented that using instruments such as those swaps may actually compromise expected liquidity access in times of market stress. (See "Methodology And Assumptions: Analysis Of Corporates' Swap-Indexed Bank Lines," published Dec. 16, 2008 on RatingsDirect.)

What is the status of deregulation throughout the U.S.?

Deregulation can best be described as stalled. For instance, the transition period for most electric providers in Pennsylvania will come to a close in 2010. Standard & Poor's expects that the rate increase in Pennsylvania will be manageable, averaging 10% to 15%, although double-digit increases during prolonged economic sluggishness could create pressure. Economic malaise in Ohio has ensnared the completion of transition plans for providers, especially FirstEnergy Corp.'s units.

The recent travails of Constellation Energy Group Inc. have Maryland leaders considering whether to order the conversion of Baltimore Gas & Electric Co. back into a fully integrated regulated company. The difficulty is that BG&E previously sold all its

generating assets as part of the original move to deregulation. Reassembling the regulated entity is a costly proposition, but reintroducing the utility's ability to self-build could happen, as it has in places like Nevada and Connecticut. In 2008, Virginia abandoned deregulation. However, it's a much less painful process for Virginia Electric & Power Co. because it never sold its generating assets.

What's the industry's growth strategy?

Before the economy went down, the growth strategy for the industry was to build power plants that they could put into their "rate-base" (the value of property on which a utility may earn a specified rate of return according to a regulatory authority) and increase assets and income through regulatory decisions. Management often targeted annual growth of 8% to 9%.

With robust capital spending likely postponed at least until 2010, earnings growth for the interim period will be sluggish. A return to a more aggressive strategic direction that includes investment in nonregulated businesses and results in higher business or financial risk would pressure credit profiles. Often, the financing of these nonregulated ventures is with leverage levels more suitable for the regulated utility asset.

How much capital spending can utilities delay without straining infrastructure?

With the slowdown and drop in customer demand for electricity, companies can delay the start of some long lead-time projects. They can also postpone a minimal amount of maintenance capital before jeopardizing service quality. Any reliability neglect--whether actual or perceived--will have a long-lasting affect on regulatory relations. Also, maintaining older infrastructure requires capital outlay.

Very little of the regulated transmission spending that companies have budgeted can be deferred considering calls from Washington for a "smarter grid" and the probable influx of renewable resources. Stricter carbon emission standards may also trigger a shutdown of older coal units, requiring spending for new, differently fired plants.

Will regulated electrics be able to build large, base-load plants?

Under the right circumstances, electric utilities will be able to build large rate-based plants. The primary consideration for how they preserve credit quality is the regulatory approval process. In the case of building new nuclear plants, we expect regulated electric utilities to have an established regulatory compact that allows them to recover costs throughout the building cycle. It's important for credit that utilities can recover these costs as they expense them. This eliminates prudence risk, customer rate shock, and excessive balance-sheet bloating.

Accurate cost estimates and negotiating contractor terms that fix a large portion of the construction expense will help keep balance sheets strong. The ability to abandon projects and recover expenses if mishaps, cost escalation, or regulatory angst occur is also beneficial to utility credit.

How important is balance-sheet strength when determining electric utility credit quality?

The electric utility industry is asset-intensive and relies heavily on debt. Balance-sheet strength is a distinguishing factor when Standard & Poor's assesses financial risk and determines credit quality. Our analysis attempts to portray the economic reality of the financial conditions and considers several items, including purchase power obligations, capital leases, hybrid equity instruments, pension liabilities, and regulatory assets.

In a period of economic decline, the strength of recovery mechanisms and the timely recovery of costs, including those for bad debt and other deferrals, keep balance sheets flexible. Monitoring leverage balances and avoiding creeping leverage caused by slow receipt of cash flow and the simultaneous conversion of short-term debt into long-term debt is important to balance-sheet strength.

Encouraging energy efficiency without recovery mechanisms burdens coverage ratio metrics. While customers are changing their consumption patterns, decoupling mechanisms allow utilities to recoup lost sales revenue. This helps mitigate cash flow pressures when usage goes down due to economic decline.

Will industry consolidation ramp up in 2009?

Standard & Poor's continues to believe that selective industry consolidation is possible in 2009, but wide-scale combinations are unlikely. Macquarie Infrastructure completed its deal for Puget Energy Inc. in about 16 months, which shows how long it can take to get regulatory approval to complete deals.

Given the length of the regulatory approval process, it's a tall order for managements to commit the time, resources, and financial obligations in a dwindling economy. However, one variable that may weigh more favorably for mergers is battered stock prices in the industry. This makes the stock-for-stock financing alternative more attractive and may spur more deals, especially if growth remains elusive.

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APPENDIX 2 - QUESTION #8

Some customers may not have the same opportunity to conserve electricity as other customers because differences such as income, access to capital, age, and renting versus owning. How should decoupling adjustments be structured to address this lesser ability to conserve?

HECO Companies Response:

Decoupling adjustments should not be put in place to manage conservation opportunities. As noted, the ability to conserve is dependent upon a number of factors, including how much conservation is already in place (through the employment of energy efficiency technologies and other energy-reduction behaviors), demographics, and what are the relative costs to additional conservation, including the costs to changes in behavior/lifestyle. Differences in customer access to opportunities to conserve or in the ability of customers to conserve can be more effectively addressed in the design of energy efficiency programs. Please also see the Companies' responses to Appendix 2 - Questions #5.3.4. and #5.3.5.

APPENDIX 2 - QUESTION #9

Please propose a customer education program for the decoupling mechanism proposed at question 2 and the allocation methodology proposed at 5.2.

HECO Companies Response:

The HECO Companies propose the following customer education program:

- 1) Prior to implementation, the HECO Companies will provide a letter to customers with an explanation of the proposed decoupling mechanism, the role and purpose of decoupling in relation to achieving the state's goal of a sustainable, clean and independent energy future, how decoupling adjustments may affect rates and customer bills, and the potential benefits to customers.
- 2) Information on decoupling will be included in *Consumer Lines*, the HECO Companies' monthly customer newsletter which is distributed to all residential customers of HECO, MECO and HELCO with their monthly electric bills.
- 3) A copy of the letter to customers, with information on decoupling (e.g., FAQs and answers) will be posted on each of the HECO Companies' websites.
- 4) The HECO Companies will develop educational materials and tools for customers to provide information on how to read monthly bills and understand the decoupling adjustment (e.g., Power to Save: Your Bill).
- 5) Information on decoupling will be made available to customers through educational displays at community events and fairs in which the HECO Companies participate throughout the year (e.g. Waianae Sunset on the Beach, Live Energy Lite, etc.).
- 6) Customer representatives will be trained to respond to questions on decoupling that may be posed by customers who contact the Companies for more information, as routinely done for new billing initiatives.

APPENDIX 2 – QUESTION #10

To the extent that the decoupling mechanism is intended to help reduce energy consumption, can this adversely affect the state's efforts to incorporate more as-available renewable energy into the grid? Can reduced consumption cause more instances where as-available energy must be curtailed due to the utility's system constraints?

HECO Companies Response:

While decoupling will eliminate the disincentive to energy efficiency that exists under traditional ratemaking, reductions in energy consumption due to energy efficiency typically occur through implementation of energy efficiency programs.

Increases in both energy efficiency and renewable energy reduce the state's dependence on oil and improve energy sustainability and security. Energy efficiency programs typically focus on measures that reduce both energy use and demand coincident with the system peak. This benefits all customers as new generating capacity is deferred and system reliability is improved. However, some end-uses affected by energy efficiency efforts also operate during off-peak periods.

Curtailment of as-available purchased energy has been identified by the HECO Companies as a challenge in Docket Nos. 2008-0021 and 00-0135.¹ This difficulty, however, is not caused by energy efficiency efforts. It is due to the usage profile of the Companies' customers who do not use as much energy during the late evening and early morning off-peak periods as during the rest of the day. To the extent that energy efficiency efforts result in lower loads during the off-peak period than if there were no energy efficiency efforts, then energy efficiency may contribute to more frequent curtailment of purchased energy. Despite that challenge, in the HCEI

¹ For example, in Docket No. 2008-0021, Maui Electric Company, Limited stated that it could only accommodate at most only one of the two wind farms proposed at the time on Maui (MECO T-1, p. 8).

Agreement, "The parties agree[d] that the maximum possible use must be made of energy efficiency, demand response and renewable energy."²

The Companies have proposed to institute voluntary residential and commercial and industrial time-of-use ("TOU") rates in their pending rate cases to encourage customers to shift electricity use out of the peak usage period into the off-peak period. In addition, per their Advanced Metering Infrastructure ("AMI") application filed in December 2008, the HECO Companies will install AMI meters upon request from customers and place those customers on interim TOU rates on an opt-out basis. Furthermore, upon completion of AMI meter installation for a commercial rate class on each island, the Companies will place the commercial rate class on a mandatory TOU rate.

The parties to the HCEI Agreement have also agreed to support alternative fuel transportation including plug-in hybrid vehicles ("PHEV"). Once PHEVs become a significant factor in transportation and are provided an electricity rate that encourages battery charging during the off-peak, they may also mitigate the problem with off-peak curtailments of as-available renewable energy.

Transitioning to "smart grids" was identified as a key objective and enabler of many HCEI initiatives. This transition will/may entail the following:

1. As wind and solar systems are added to the utilities' grids, particularly at the distribution level, having "smart grids" will enable the HECO Companies to increase their real-time monitoring of the transmission and distribution system capability, including monitoring environmental factors such as wind speed, sunlight intensity, and temperature.
2. In conjunction with increased data collection capability, it may be necessary to install and implement enhanced forecasting and monitoring systems to better predict the wind and cloud patterns that affect variable generation.

² HCEI Agreement, Section 23 Resource Attributes: The Loading Order, page 29.

3. Increasing the capability to remotely and automatically control transmission and distribution systems through the use of remote switching devices, voltage regulations devices, protective relaying, and individual distributed generation installations and individual loads.
4. Upgrading the relay system to accommodate dynamic settings and higher penetration of distributed generation.
5. Implementing distribution automation: transmission and distribution technologies and microgrids which address self-healing, resistance to attacks, power quality, and accommodation of non-renewable generation (HCEI Agreement at 31).

Hence, the deployment of "smart grids" will provide the HECO Companies improved prediction and monitoring capability of environment factors affecting renewable energy generation sources. This should enable the HECO Companies to better manage and control of curtailments of renewable sources, so as to maximize acceptance of power from these sources.

APPENDIX 2 - QUESTION #11

Do the rate changes associated with the decoupling mechanism merit a new rate case for HECO pursuant to Hawaii Revised Statutes, Chapter 269, or can the changes be accomplished within the scope of the existing HECO rate case? Are public hearings needed, considering the extent of the expected rate changes?

HECO Companies Response:

No. The rate changes associated with the decoupling mechanism would occur subsequent to and outside of a rate case. Similar to the integrated resource planning ("IRP") cost recovery provision, the decoupling mechanism is an automatic rate adjustment clause and therefore any increase in rates resulting from the decoupling mechanism would not constitute a general rate increase and would not require a rate case. The Hawaii Administrative Rules ("HAR"), §6-61-2, provides the following definition:

"General rate increase" means a partial or flat increase in the general level of the rates or charges for revenue purposes or to increase the rate of return. The establishment of a rate or charge for a new service, an adjustment of or a change in a particular rate or charges for the purpose of eliminating inequities, preferences, or discriminations, or increases in rates or charges resulting from an automatic rate adjustment clause are not general rate increases. [Emphasis added.]

HAR 6-61-85(b) makes clear that the Commission rules on general rate increases (i.e., rate cases) in Subchapter 8 of Chapter 6-61 of the HAR do not apply to rate changes pursuant to an automatic rate adjustment clause.

'6-61-85 General provisions. (a) In order for the commission to schedule its future workload requirements in an efficient manner, every public utility and water carrier shall file with the commission a notice of intent to file a general rate increase not less than two months before filing its application or notice of increase, except that the foregoing does not apply to a public utility with annual gross utility operating revenues under \$2,000,000. The carrier or applicant shall serve a copy of the notice of intent on the consumer advocate and the mayor of each county affected by the proposed rate increase. Proof of service must be filed

with the notice of intent. The filing of a notice of intent does not set any hearing scheduling priorities for the public utility or water carrier that files the notice.

(b) This subchapter does not apply to changes pursuant to an automatic rate adjustment clause. [Emphasis added.]

Since the decoupling mechanism is an automatic rate adjustment clause, the rate changes resulting from the decoupling mechanism would not be subject to the notice or hearing requirements in the Hawaii Revised Statutes ("HRS"), §269-16(b), which state the following:

(b) No rate, fare, charge, classification, schedule, rule, or practice, other than one established pursuant to an automatic rate adjustment clause previously approved by the commission, shall be established, abandoned, modified, or departed from by any public utility, except after thirty days' notice to the commission as prescribed in section 269-12(b), and prior approval by the commission for any increases in rates, fares, or charges. The commission, in its discretion and for good cause shown, may allow any rate, fare, charge, classification, schedule, rule, or practice to be established, abandoned, modified, or departed from upon notice less than that provided for in section 269-12(b). A contested case hearing shall be held in connection with any increase in rates, and the hearing shall be preceded by a public hearing as prescribed in section 269-12(c), at which the consumers or patrons of the public utility may present testimony to the commission concerning the increase... [Emphasis added.]

Pursuant to the above, the Commission has not held contested case or public hearings when increases have resulted from automatic rate adjustment clauses like the IRP cost recovery provision. Rather, the HECO Companies have routinely filed tariff pages every month on not less than one day's notice to implement rate changes for the IRP cost recovery provision, outside of a rate case and without contested case or public hearings.¹

In its current 2009 test year rate case (Docket No. 2008-0083), HECO does not propose rate changes associated with a decoupling mechanism. It proposes to establish a revenue balancing account ("RBA") to record the differences between the approved revenue

¹ The "HECO Companies" or "Companies" are Hawaiian Electric Company, Inc. ("HECO"), Hawaii Electric Light Company, Inc. ("HELCO") and Maui Electric Company, Limited ("MECO").

requirements (i.e., the target revenues) and recorded revenues, to be effective upon the issuance of the interim decision and order in that rate case. This is consistent with the *Energy Agreement among the State of Hawaii, Division of Consumer Advocacy of the Department of Commerce and Consumer Affairs, and the Hawaiian Electric Companies* ("HCEI Agreement"), which states: "The revenues of the utility will be fully decoupled from sales/revenues beginning with the interim decision in the 2009 Hawaiian Electric Company Rate Case (most likely in the summer of 2009)." The HECO Companies propose to file tariff rates in the November 2009 time frame reflecting the year-end estimated RBA balance and the impact of a revenue adjustment mechanism ("RAM") to be effective on January 1, 2010.² See Attachment 1 of the HECO T-1 Rate Case Update in Docket No. 2008-0083. The Companies would follow this process in each year of the post-test year period.

² The HECO Companies have submitted a RAM proposal in the decoupling proceeding (Docket No. 2008-0274).

APPENDIX 2 - QUESTION #12

Various provisions of the HCEI propose utility surcharges, where the utility will fairly immediately recover its costs (potentially both fixed and variable) through a surcharge that is separate from the normal rates. How can the commission effectively decouple this aspect of the utility rates? Do these surcharges impact the effectiveness of the efforts to decouple rates from earning?

12.1 Please provide details of changes that need to be made to the various HCEI proposals that have already been filed as a result of decoupling.

HECO Companies Response:

The HCEI Agreement proposes a Clean Energy Initiative ("CEI") surcharge¹ to recover the return on and return of investments in renewable energy infrastructure and a purchased power adjustment to recover non-energy purchased power costs not already covered by the Energy Cost Adjustment Clause². Since these fixed costs and non-energy purchased power expenses are proposed to be recovered outside of base rates, they are not covered by the sales decoupling mechanism, nor should they be. Also, in the Companies' decoupling proposal, fuel and purchased power expenses (whose cost variation would be recovered through the ECAC and Purchased Power Adjustment Clause) and DSM expenses and Solar Saver costs (which are in the DSM component of the IRP cost recovery provision) are removed to determine the revenue adjustment mechanism ("RAM"). Pension and OPEB expenses are also removed since recovery of these expenses are still subject to trackers.³

The Companies do not anticipate that the CEI surcharge will impact the effectiveness of decoupling revenues from sales. The CEI surcharge will be addressed in a separate proceeding where issues related to the surcharge will be further investigated.

12.1. See response above.

¹ HCEI Agreement at 34-35.

² Ibid at 35-36.

³ More detailed discussion is provided in "Revenue Decoupling Proposal of the Hawaiian Electric Companies," filed on January 30, 2009, and corrected on February 3, 2009, in Docket No. 2008-0274, at 18.